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Economic Impact of EPA's Regulations on
the Pet. Refining Ind. Vol. 2. Pts. 1&2.
Ind. Description & Tech. Analysis

Sobotka and Co., Inc.

Prepared For
Environmental Protection Agency

April 1976

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**ECONOMIC IMPACT OF EPA'S REGULATIONS
ON THE PETROLEUM REFINING INDUSTRY**

**Parts One and Two
Industry Description and Technical Analysis**

**APRIL 1976
FINAL REPORT**

Contract No. 68-01-2830

**Prepared by
U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Planning and Evaluation
Washington, D.C. 10460**

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ECONOMIC IMPACT OF EPA'S REGULATIONS
ON THE PETROLEUM REFINING INDUSTRY

Part One

APRIL 1976
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Contract No. 68-01-2830

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PART TWO FOLLOWS PART ONE IN THIS VOLUME

PREFACE

GOVERNMENT INFLUENCE ON THE ECONOMIC
WELL-BEING OF THE PETROLEUM REFINING INDUSTRY

The economic well-being of this industry is greatly influenced by United States and foreign government policies unrelated to environmental considerations. Both the legislative and the executive branches of the government are considering policies and legislation which will (or may) considerably affect this industry. These policies have been in a state of flux for some years, but recent legislation presents a better basis for forward planning than has existed for many years. However, there is little prospect that uncertainty resulting from the government's desire to shape the development of the petroleum industry will soon cease.

The impact of environmental rules may well be influenced by the policies which govern the development of the industry in the next several years. Consequently, a discussion of the probable impact of government policies on the petroleum industry's economic development, and of the relation of these policies to the ability (or incentive) to absorb environmental costs by the industry is in order.

Until fairly recently, the output of the refining industry had grown at a steady rate. This would not have happened in the absence of economic incentives necessary to attract capital to the industry. As long as normal market incentives prevailed, the viability of firms within the industry was governed by their relative economic efficiency. Except for the oil import control and small business set-aside programs, which substantially aided small firms, there was little government influence on market incentives prior to the abolition of the quota system and the rise of foreign crude oil prices to, and above, domestic levels in 1973.

With the imposition of price controls, and mandatory product and crude oil allocations, normal economic incentives ceased functioning. For example, during the winter 1973/1974 a mandatory program to regulate refinery product mix was in force which reduced gasoline and increased distillate as well as residual oil out-turn. At the same time price controls prevented normal economic incentives from allocating products. Also, since the winter 1973/1974 there has simultaneously been in force a crude oil allocation system which mandates a distribution among refiners of the total supply of crude oil produced in, or imported into the United States. Recently the system has been further supplemented with a crude oil entitlement, or cost equilization program, under which the comparatively lower cost, price-controlled oil is allocated according to a (changing) formula which reflects the allocator's notion of equity or political realities, rather than the working of natural economic forces. Under this program, the rights to purchase price-controlled "old" oil are allocated to refiners on the basis of refinery runs. Thus, a company's current cost of crude oil acquisition is determined by government regulation, rather than by its own current or past business decisions and acumen. This form of government intervention affects both the absolute and the relative profitability of firms in the industry. Moreover, it very significantly alters the incentive structure away from that which would prevail if free market forces were allowed to operate.

The Congress is now considering legislation which would significantly restrict petroleum companies' allowed areas of operations. For example, proposals which would prohibit crude oil producers from marketing oil products have been made. Under other proposals marketing and manufacturing could not be conducted by the same firm, or pipelines would have to be divested, or petroleum companies would be prohibited from mining coal or producing energy in other "non-oil" forms.

It is not within the scope of this project to discuss the desirability of the non-market rules now in effect. However, it is necessary to point out that their economic impact is very large. For example, a refiner who, under the current crude oil entitlement program, is granted a substantially larger quota of lower priced "old" crude oil than he would be able to purchase on the open market is given a great deal of assistance by government. On the other hand, a refinery who, because of price controls, cannot charge market clearing prices - even if the effect of price controls is to hold average prices only a few percentage points below equilibrium levels - may have his income reduced substantially below the levels that would prevail in a free market.

It is important to recognize the role of industry growth, or the lack of it, on the petroleum industry's ability to recover the capital costs imposed by environmental regulations. If the industry as a whole is growing, and capital is being invested in new or growth facilities, then it is reasonable to expect that aggregate of product prices (and hence refiner's margins) will be sufficiently high to attract capital to the industry. In this case there will be returns earned at least on that portion of environmental capital associated with growth. Because the pricing of industry products from new or existing facilities are indistinguishable, the prices will then also be high enough to defray the costs of environmental capital expenditures on existing facilities to the extent that they do not exceed the per unit costs in new facilities.

However, if the industry is not growing and no capital is required for the expansion of existing facilities or the construction of new plants, recovery of the costs of environmental capital presumably will not take place. In the no growth case, industry prices will only be sufficient to cover the variable costs of operating existing facilities. This will be the normal result of competition between firms who do not need to attract capital to expand their output capabilities. Under these conditions the bulk of the environmental expenditures to

bring existing facilities into conformance with environmental standards would have to be absorbed by the refining industry, which would tend to magnify the economic difficulties of those refiners who already are at a cost disadvantage due to size, location or type of equipment.

PART ONE

INDUSTRY DESCRIPTION

INTRODUCTION AND SUMMARY

This is Part One of a three-part report which studies the economic impacts of the costs of pollution abatement requirements imposed by the Federal Environmental Protection Agency on the petroleum refining industry (SIC 2911). This study is limited to assessing the economic impact of pollution abatement costs which result from regulation of petroleum refinery operations; the costs resulting in other activities within the petroleum industry, such as exploration and production, transportation, and marketing, are not within the scope of this study.

The impact of limitations on emissions into the atmosphere and into water, and product quality regulations are the primary concern, and the study analyzes the impact of existing federal regulations and of state or local regulations or Federal law (or rules) not based on environmental considerations are excluded from the impact analysis and are considered part of base costs.

The level of emission control used in the study is that envisaged under current and currently-proposed regulations. The base period for the analysis is 1973 operations and the period 1974-1983 is covered in the study, with subdivisions made.

Costs that have been incurred through 1973 (which by now are sunk, and therefore cannot be minimized or retrieved) are not detailed. The reason for focusing on the period 1974 through 1983 is that the purpose of the study is to aid the Government in making decisions with respect to environmental regulations in the months and years ahead, and to enable people generally to make informed judgments about the costs and economic impacts of environmental regulations.

The study is presented in three parts. Part One consists of a description of the industry and its financial profile. Part Two measures investment and operating costs which are incurred by the refining industry in the specific areas of refinery water effluent guidelines, atmospheric emissions from refineries, and product quality regulations. Finally, Part Three considers in detail the cost impacts of environmental regulations and the effect on the prices of the industry's products, industry growth, profitability, changes in industry output, including changes in the number, size and location of plants that may close or curtail production, or to significantly increase production, with the associated changes in employment in the industry, localized community impacts, and impacts on imports and exports of the products of the industry and its raw material supplies.

The choice of data and description of the refining industry which are presented in this part of the study are influenced by two considerations. First, to present information valuable to persons who guide the making of public policy for this industry. Secondly, to discuss those aspects of the industry's relations with other industries which would be useful in assessing the impact of pollution abatement costs in the economy generally.

- - - - -

The petroleum refining industry in the United States and its possessions consists of some 277 plants, owned by about 139 firms, and located in 40 of the 50 states, Guam, Puerto Rico, and the Virgin Islands. The refineries have a replacement value in excess of \$30 billion. The refinery industry employs about 150,000 persons.

The bulk of refining is done by firms which also market refined products or produce crude oil, or do both. In most firms the refining portion of the business is not its major activity.

Refinery investment is less than 15 percent of total investment in the domestic oil industry. Refinery employment is a somewhat larger fraction of total employment. The industry has grown at a fairly steady rate, but slower than real GNP.

The U.S. refining industry is in a period of profound change. For over 15 years the industry was protected from lower-cost foreign competition by an import quota system on products as well as crude oil. But industry capacity grew at a slower rate than did product demand. Price controls were imposed in August, 1971. They are still in effect but, according to present legislation, will be phased out in about 3-1/2 years.

World crude oil prices have been forced up to about 3 or 4 times their 1971-1972 levels by the cartel of producing countries. They are now greater than the average of U.S. prices which are price controlled. Despite these high prices, oil product and crude oil imports have increased until 1974 because domestic crude oil production has failed to keep pace with growth in consumption. In 1975 crude oil imports decreased slightly, probably as a result of the continuation of recession and high costs which have inhibited demand for petroleum products. Domestic production of crude oil also declined, but not due to a decline in demand. The domestic industry's ability to produce is in a period of decline resulting, in part, from the investment climate prevailing prior to the recent price increases.

Due to recent price increases of petroleum products demand growth is now lower than had previously been expected. Escalating costs and environmental problems may also have restricted new plants. Since Mobil's Joliet refinery went on-stream in 1972, no new major refinery has come on-stream, and the next one will not be completed until 1976. Two grassroot refineries with capacities below 50,000 barrels per day have come on-stream in the interim. There have been a substantial number of refinery expansions and modernizations at existing plant sites, some of them of large magnitude. It is frequently less costly to modernize

and expand an existing plant than to construct a new one. This is because technological improvements create the opportunity to use existing facilities more economically or to expand large segments of existing plants. Also some of the delays and costs resulting from environmental rules, zoning limitations and the like, can be avoided by expanding existing facilities. On the other hand, many announced large grassroot refineries and a number of announced expansions/modernizations have been cancelled.

Compared to the above discussed major changes in the economic environment, within which the industry operates, pollution abatement costs will be small, and therefore the impact of pollution abatements on the refining industry in aggregate will also be small.

CHAPTER I

DEMAND

A. The Products

The industry manufactures hundreds of distinguishably different products. From the viewpoint of environmental control costs, these may be grouped into four broad product classes: gasoline, middle distillates (often referred to as intermediates), residual, and other.

Gasoline accounts for about 45 percent of industry output volume. It is currently priced at about 30 cents per gallon¹⁾ in cargo lots on the Gulf Coast. Although other materials can be used as gasoline substitutes, (propane, methyl and ethyl alcohol, electric batteries) their use is negligible for cost reasons. Economics and government policy may at least temporarily decrease the fraction of crude oil going to gasoline. This might happen if the evolving import control program is more evenhanded than the previous one with respect to residual oil or if increases in the price of gasoline, due to new taxes or for other reasons, inhibit sales of gasoline more than of other products.

Intermediates include military and commercial jet fuel, kerosene, space heating oil, also called No. 2 fuel oil or furnace oil, and diesel fuel. These products are currently also priced at about 30 cents per gallon and make up about 33 percent of industry output. No substitutes exist for the transportation fuel portion of the intermediates' market. Natural gas is more extensively in the space heating market and may be more or less expensive than oil, depending on user location and government price control policy. Some heating oil is imported, which reduces the demand for domestic product.

¹⁾ Platt's Oilgram 12/6/74.

²⁾ See the discussion of residual oil which follows.

Residual is currently priced at from about 25 cents to about 32 cents per gallon or even more, depending on sulfur content and location. Residual amounts to about 8 percent of domestic petroleum production and 15.5 percent of domestic demand for oils. The difference is accounted for by imports. Through most of the 1960's residual was priced sufficiently below crude oil as a result of government import policies to prompt increased investment in domestic refineries in order to reduce residual yields. Currently, residual oil is treated as any other refined product. Consequently, the incentive to reduce residual yields exists only to the extent that this product competes with energy forms not produced from crude oil. In large volume installations, natural gas and coal compete directly with residual oil.

Other products include asphalt, lubricants, liquefied petroleum gas (mostly propane), naphthas and solvents, coke, petrochemicals and petrochemical feedstocks. (Asphalt and lubricating oils are important products for many small refineries.) These products account for about 16 percent of the domestic industry's output. They are priced from 25 cents to \$1.00 or even more per gallon. Most lubricants and liquefied petroleum gas (LPG) have no significant economical substitutes from outside the industry. On the other hand, petroleum solvents face direct competition from the chemical industry. Non-metallurgical petroleum coke is exported in significant amounts. The market for this product depends in large part on emission rules in customer countries.

B. Market and Distribution

The U.S. petroleum market is divided into five geographic regions called "PAD Districts". (See Exhibit 1). Product consumption is also classified by end use.

Market data for 1969 through 1973 by product and District are shown in Exhibits 2, 2a, and 2b.

Oil products are distributed from refineries to terminals primarily by pipeline and tankers or barges. From there, local deliveries are made by truck. Some minor rail distribution is utilized. The impact of new environmental standards on the distribution and marketing of oil products does not fall within the scope of this study. But the costs of meeting new standards in moving the products from the refinery to the final consumer in the associated storage facilities, including terminals and service stations, may be important. Environmental standards applicable to exploration and production of crude oil and natural gas also impose costs on the industry. The impacts of these costs also are not a part of this study.

From the viewpoint of dollar volume, gasoline accounts for roughly 50 percent of the refining industry's value of output. Intermediates account for 33 percent, and residual for only 6 percent.¹⁾ Well over one-half of total refinery output is sold through distribution and marketing facilities which refining companies own or in which they have a financial interest. In general, sales of gasoline and jet fuel are more highly integrated than are distillate and residual oil. Most large companies operate their refining, distribution and marketing functions in an integrated manner. Assigning product prices at various points within the operation is an internal matter to most companies. Nevertheless, product is often sold by refiners directly to customers in arm's-length transactions, especially to Federal, state or local government consumers. Thus, conclusions adequate for this study can be drawn about the costs associated with EPA's environmental standards.

¹⁾ Because of residual imports, and different product integration levels for distribution/marketing, the relative contribution of the various products to domestic refiners' gross dollar revenue is different than the relative contribution at the consumer level.

Exhibit I

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS

Exhibit 2

DOMESTIC DEMAND FOR PETROLEUM PRODUCTS
Thousand Barrels Per Day

Product	Year	P.A.D. DISTRICT					U.S.
		I	II	III	IV	V	
Automotive Gasoline	1973	2,221	2,311	966	204	971	6,673
	1972	2,161	2,206	884	188	937	6,376
	1971	2,041	2,080	825	199	869	6,014
	1970	2,000	2,008	729	186	861	5,784
	1969	1,704	1,930	705	170	817	5,526
Jet Fuel Naphtha Type	1973	62	36	46	8	65	217
	1972	64	45	40	7	86	242
	1971	77	49	40	6	88	260
	1970	66	43	37	7	94	247
	1969	80	46	59	8	104	297
Jet Fuel Kerosene Type	1973	349	169	53	23	239	833
	1972	332	167	50	19	235	803
	1971	303	158	48	19	223	751
	1970	284	150	50	20	212	716
	1969	265	145	50	19	215	694
Kerosene (Ex Jet)	1973	90	64	53	5	4	216
	1972	119	67	38	6	4	234
	1971	130	77	32	5	5	249
	1970	126	83	43	6	5	263
	1969	144	83	39	6	3	275
Distillate Fuel Oil	1973	1,426	910	339	95	310	3,080
	1972	1,396	883	278	84	272	2,913
	1971	1,326	783	206	82	264	2,661
	1970	1,308	738	191	71	232	2,540
	1969	1,272	715	176	72	231	2,466
Residual Fuel Oil	1973	1,918	236	193	26	421	2,794
	1972	1,876	219	87	26	321	2,529
	1971	1,715	181	76	26	297	2,295
	1970	1,643	190	87	25	257	2,202
	1969	1,412	173	78	35	281	1,979

Source: Bureau of Mines, Mineral Industry Survey - Petroleum

Exhibit 2a

U. S. SALES OF DISTILLATE FUEL OIL, BY USES 1969 - 1973
(Thousands of Barrels)

Repro
best

Diesel Engine
Fuel (Excl.
Railroads)

Oil
Company
Fuel

Industrial

Railroads

Electric
Utility
Company

Vessels

Year

Total Domestic Sales
Excluding
Fuel for
Oil

All Uses

Company
Use

Miscellaneous

Military

Heating

1,124,200
1,063,245
971,320
927,250
900,300

1,109,235
1,049,740
937,232
915,732
856,433

5,475
2,190
17,427
12,447
12,534

19,710
20,078
17,427
12,447
13,958

535,820
541,660
523,648
521,135
511,768

1973
1972
1971
1970
1969

273,385
238,710
213,906
194,919
186,253

67,166
60,225
49,558
43,668
42,456

14,965
13,505
14,043
11,513
13,567

12,230
10,725
86,251
88,116
86,429

35,110
42,357
35,320
44,770
12,158

26,645
21,900
20,959
19,503
18,577

1973
1972
1971
1970
1969


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Source: Bureau of Mines, Mineral Industry Surveys, "Sales of fuel Oil and Kerosine," Annual.

Exhibit 2b

U. S. SALES OF RESIDUAL FUEL OIL, BY USES, 1968 - 1973
(Thousands of Barrels)

Year	Vessels	Electric Utility Company	Railroads	Oil Company Fuel	Industrial
1973	91,980	509,540	1,095	50,735	150,380
1972	77,745	434,350	1,095	44,165	141,985
1971	76,727	371,820	1,262	32,626	135,647
1970	69,850	312,420	2,222	35,318	139,647
1969	83,481	247,634	3,381	36,559	133,754
1968	87,575	184,956	4,296	39,329	135,664

Total Domestic Sales			
Excluding			
Fuel for			
Oil			
Year	Heating	Military	Miscel- laneous
1973	187,975	19,345	9,125
1972	190,530	24,455	8,760
1971	182,639	29,217	6,109
1970	185,831	28,704	7,295
1969	178,095	31,750	7,875
1968	174,326	34,990	8,348

Total Domestic Sales		
Excluding		
Fuel for		
Oil		
Year	Company Use	All Uses
1973	969,440	1,020,175
1972	878,920	923,085
1971	805,243	837,869
1970	765,969	804,287
1969	685,970	722,529
1968	630,155	669,484

Source: Bureau of Mines, Mineral Industry Surveys, "Sales of Fuel Oil and Kerosine," Annual.

Prior to the oil embargo, in the four years from 1969 to 1973, the volume of gasoline produced had increased at an average annual rate of 5.1 percent. Intermediates consumption had grown at 5.5 percent per year. Residual production in domestic refineries had been stable, but consumption had increased at about 8.6 percent per year. Since 1973, due to the embargo, it is pointless to compare recent data with historical growth rates.

Prior to the oil embargo of 1973/74, oil product prices had increased at a slower rate than either consumer or wholesale price indices, largely because the industry had been able to utilize improved technology to offset increases. In the absence of price controls, important short-term price changes do occur, mostly associated with changes in refinery utilization and with seasonal factors. Also, since crude oil accounts for over two-thirds of the cost of oil products at the refinery gate, product prices change with the price of crude. In recent years, product price changes have been largely the result of crude oil cost increases.

C. Government Influence on Market

Foreign, Federal, state and local governments all influence the oil product market. In the recent past, the Federal government's major influence has been through taxes, price controls and tariffs (fees) on imports of crude oil and products. Price controls hold prices down and discourage investment. It is not clear now what type of program will be in force for the next decade. From 1957 to April, 1973, importation of crude oil was limited by a quota system, and products imports, except for residual oil, were held at very low levels. Foreign crude prices had, until 1973, been lower than domestic, so import rights normally had had considerable value. These rights were allocated among refining firms according to their size. Although large firms had bigger quotas than small ones, the latter were given a larger allocation per unit of throughput. Currently,

imports are not quantitatively limited and, indeed, are somewhat encouraged by the combination of domestic price controls and the way in which the entitlements to purchase domestic crude oil are allocated.

All levels of government purchase large quantities and a wide range of oil products. One of these purchases, military grade jet fuel (JP-4), is important to some small refiners. A gasoline boiling range material, JP-4 requires little processing beyond separation from crude. In contrast, automotive gasoline is produced in a complex processing scheme.

Government also influences the market for petroleum products through imposition of environmental standards. This can take the form of direct specification of product characteristics, e.g., sulfur content in residual oil. Or it may take the form of imposing environmental standards on petroleum product users which in turn affect the nature of the product. For example, control of auto emissions has resulted in a demand for unleaded gasoline. In both cases probable costs for changes in product characteristics exceed the cost of EPA environmental standards regulating direct emissions from refining operations.

Government policy in pricing and regulation of natural gas also affects refining costs. This is because natural gas is a refinery fuel, a hydrogen plant feed stock, a refinery product, and a substitute in use for other refinery products.

CHAPTER II

SUPPLY

A. Industry Operations

1. The production process.

Although a typical oil refinery is technically complex, the manufacturing process is conceptually simple.

Crude oil is the primary raw material used in refining. Crude oils are liquid mixtures of many carbon-containing chemical compounds. Crudes differ from one another in the relative concentration of the various compounds. In refining, crude oil is first separated into several groups of varying molecular sizes known as cuts. The chemical composition of some of these cuts is then altered by changing the average molecular size. Some cuts are further processed to alter the shape or structure of the molecules. Most of the original and the altered cuts are "treated" to make innocuous or to remove impurities, notably sulfur. Treated cuts are then blended to produce finished products. To these may be added various substances, known as additives, to impart certain desirable properties. Exhibit 3 classifies various refinery processes according to their principal function in the refining of petroleum: separation, alteration of molecules by size or shape, or treating. A schematic flow diagram of a refinery is shown in Exhibit 4.

In refinery operation, certain polluting materials may be released into the environment. The pollutants are by-products of the various refinery processes.

The principal ones arise in operations as follows:

- a. Hydrogen sulfide (H_2S) is present in many crude oils and is formed in hydroprocessing (catalytic reforming, hydrotreating, and hydrocracking) and

cracking (catalytic and thermal, including coking). Only trivial amounts, which can be ignored, are formed in other processes. Because H_2S is highly poisonous, it is either recovered (and converted to elemental sulfur) or burned. Burning forms sulfur oxides, which are air pollutants.

Sulfur oxides are also formed in the combustion of sulfur containing liquid refinery fuels. If these fuels also contain nitrogen compounds, the formation of NO_x is enhanced. This NO_x , as well as the small amount of SO_3 formed from sulfur compounds in the fuel, tend to be the principal cause of stack plumes in refinery furnaces. Burning coal would, of course, also add to the problem of particulates emission. An additional source of SO_x emissions are the incinerated tail gases from sulfur recovery units.

b. Hydrocarbon vapors can escape from refinery tanks containing crude oil, gasoline, and volatile intermediate products. Other sources of hydrocarbon vapor emissions are tank truck and tank car loading, volatiles unloading facilities, and oil separators in the aqueous effluent treating system.

c. Carbon monoxide emission in refineries is confined to the flue gases from catalytic cracker regenerators and fluid coker coke heaters.

d. Particulate emission in a refinery is significant only from catalytic crackers and fluid cokers unless a refinery burns coal or coke as fuel.

e. Substances which create a biological oxygen demand (BOD) in waste water are formed in catalytic and

Exhibit 3

FUNCTIONAL CHARACTERIZATION
OF
PETROLEUM REFINERY PROCESSES

A. HYDROCARBON REFINING PROCESSESPrincipal Process Purpose

MOLECULAR CHARACTERISTIC ACTED UPON	SIZE (Mole Weight)	<u>Separation</u>	<u>Alteration (Conversion)</u>
		Distillation (atmospheric and vacuum crude fractionation, naphtha splitting, depropanizing, debutanizing, vacuum flashing)	Thermal Cracking (visbreaking, coking)
		Absorption (recovery of ethane- or propane-and-heavier from saturated or cracked gas)	Catalytic Cracking
		Extraction (deasphalting)	Hydrocracking
			Alkylation
			Polymerization
	SHAPE (Mole Structure)	Extraction (solvent extraction for separating aromatics from naphtha, lube oil, etc.)	Catalytic Reforming
		Crystallization (dewaxing of lube oil)	Isomerization

B. TREATING PROCESSES

Hydrotreating

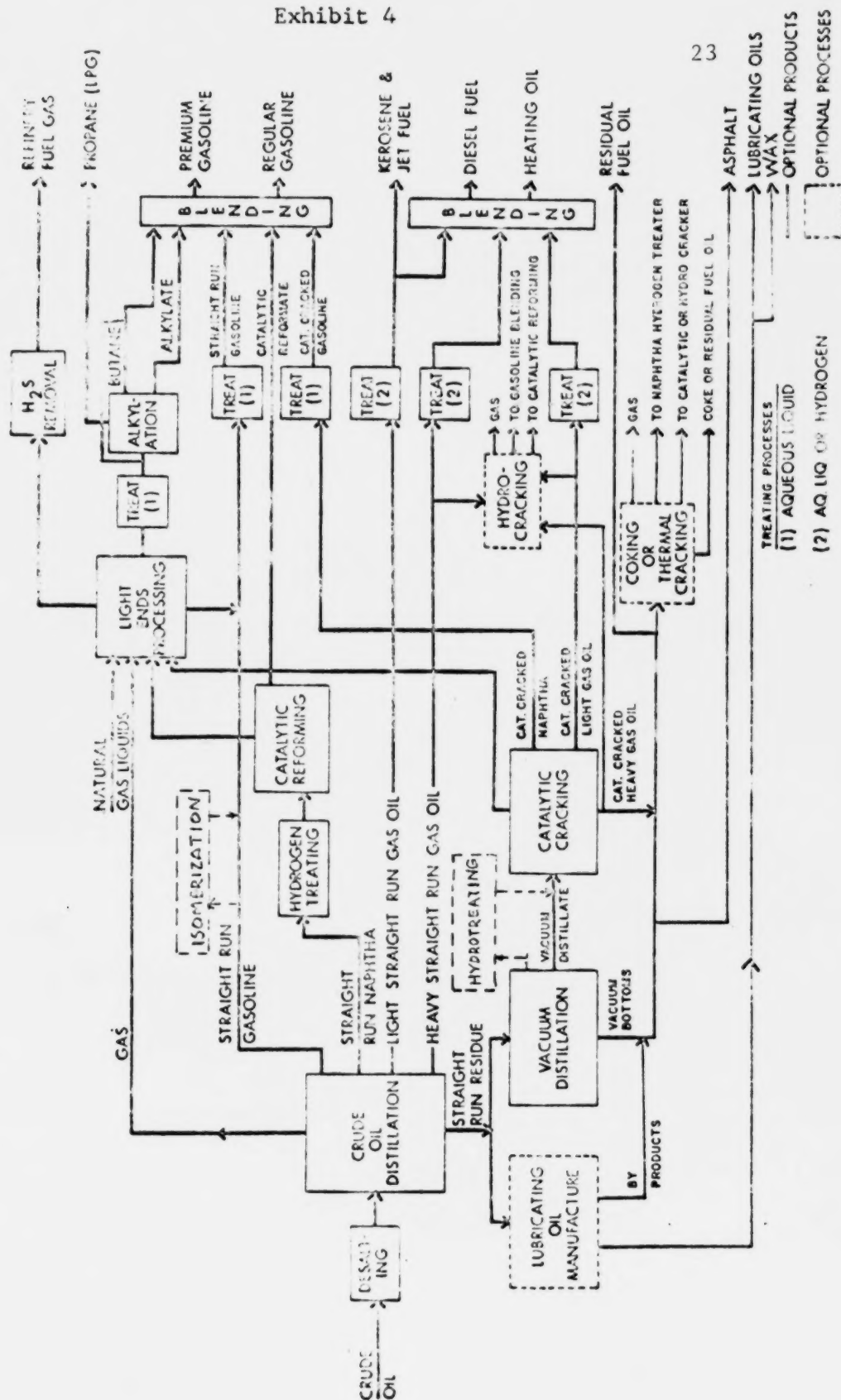
Caustic Treating (Merox, Bender, etc.)

Clay Treating

Acid Treating

REFINERY FLOW PRODUCT MANUFACTURING

Exhibit 4



thermal cracking and in sulfuric acid treatment of petroleum products (notably naphthenic and Pennsylvania lubricating oils). Also most of the solvents (phenol, furfural, etc.) used in manufacturing solvent-refined lubricating oils create BOD.

f. Entrained hydrocarbons and dissolved contaminants such as ammonia, light mercaptans and salt (from crude and cooling water treatment) are found in refinery waste water streams. These contaminants may also cause the pH of the water to be outside permissible limits.

Processes used to control the emission of these pollutants are shown in Exhibit 5. The schematic flow diagram in Exhibit 6 shows the collection and treatment of pollutants produced in each process.

The foregoing classification can be summarized as follows:

<u>Refining Processes Installed</u>				<u>Effluent Control Required</u>		
<u>Large Cat. Cracker</u>	<u>Thermal or Small Cat. Cracker</u>	<u>Hydro- Proces- ses</u>	<u>Lube Mfg.</u>	<u>Air</u>		<u>Water</u>
				<u>H₂S</u>	<u>CO & Cat.</u>	<u>BOD</u>
X				X	X	X
	X			X		X
		X		X		
			X			X

The imposition of environmental controls on the quality of refinery products adds additional processing complexity to refineries. For example, much more catalytic reforming, as well as some other processes, will be introduced to make unleaded gasoline. Intermediates will require hydro-desulfurization. The manufacture of low-sulfur residual will require installation of considerable equipment. At the moment, the low-sulfur residual

REFINERY ENVIRONMENTAL CONTROL PROCESSES

<u>Environmental Problem</u>	<u>Control Process(es)</u>
Hydrogen sulfide is highly toxic. Reacts to form sulfur oxides if burned.	1. Gases containing hydrogen sulfide (H_2S) are treated with a liquid (usually an amine solution) which preferentially absorbs H_2S. The H_2S is recovered by stripping it from the liquid. It is subsequently converted to sulfur and recovered. 2. Sour water stripping. Aqueous effluents from refinery processes which contain H_2S are steam stripped to remove the H_2S. (The recovered H_2S is generally converted to sulfur or burned, if within permissible emission limits.)
Sulfur oxides. Emitted to the atmosphere with flue gases from burning fuels containing sulfur. Irritating to eyes and respiratory system. Also, SO_3 causes opaque "plume."	1. Hydrodesulfurization. The sulfur-containing oil is reacted with hydrogen at elevated temperatures and pressures in the presence of a solid catalyst. Sulfur in organic compounds is converted to H_2S. (Hydrogen for the hydrodesulfurization process is generally recovered as a by-product of catalytic reforming or manufactured by converting either natural gas or refinery by-product gases.)

<u>Environmental Problem</u>	<u>Control Process(es)</u>
	2. Sulfur plant (Claus Plant) vent gas containing unrecovered SO_2 and H_2S is incinerated with extra fuel to SO_2 where emission rules permit. If not, tail gas recovery processes are available which either convert the sulfur components to sulfur or to concentrated H_2S for recycling to the Claus Plant.
Carbon monoxide. Present in stack gas from catalytic cracking units. Poisonous to animal life.	1. Revising cat cracker regenerator conditions to higher temperatures (1350-1450 F) permits complete combustion of CO to CO_2. Alternately, the stack gas is enriched with fuel and burned totally to CO_2 in an external furnace which may either be a steam generator or process heater.
Smoke. Produced when insufficient air is used in firing boilers and furnaces or by incomplete incineration of process materials vented and flared because of upsets.	1. Proper control of boilers and furnaces. 2. Incinerate vented materials in a "smokeless flare."
Hydrocarbon vapors. Evaporated from tanks or small leaks and spills. React in atmosphere to cause smog.	1. Install floating roofs or vapor recovery system on tanks. 2. Good housekeeping practices - fix leaks, maintain pump seals, clean up spills, etc.

<u>Environmental Problem</u>	<u>Control Process(es)</u>
Oil (and water insoluble non-hydrocarbon liquid organic compounds) entrained in refinery waste water. Harmful to aquatic life and dirty.	1. API Separator. Oil is allowed to rise to the surface of the contaminated water and is skimmed off. 2. Aeration. Air is blown through the contaminated water. Oil rises to the surface as froth and is skimmed off.
Water-soluble organic compounds. Dissolved in refinery waste water. Many compounds toxic to aquatic life. Also reduce oxygen content of receiving water body which leads to aquatic life damage. May also smell badly.	1. Biological treatment. a) Trickle filter. Contaminated water is trickled through a pile of rocks on which live colonies of bacteria. The bacteria convert the contaminants into harmless compounds (mostly water and carbon dioxide). b) Activated sludge treater. Contaminated water is contacted with a suspension of bacterial colonies, nutrients and air. The bacteria convert the contaminants into harmless compounds. Clean water is separated by settling of bacterial sludge.
Phenolic compounds. Produced in cracking processes and extracted from cracked products. Toxic to aquatic life.	1. Sold to Chemical industry. 2. Incinerated. 3. Pumped into underground formation which is sealed to prevent contaminating fresh water.

Environmental ProblemsControl Process(es)

Fluid catalyst. Entrained in stack gas from catalytic cracking units.

4. Hydrotreat the cracked product to eliminate the need to extract phenols.
5. Recovery by solvent extraction or solution adsorption.
6. Oxidation in cooling towers or over a catalyst.

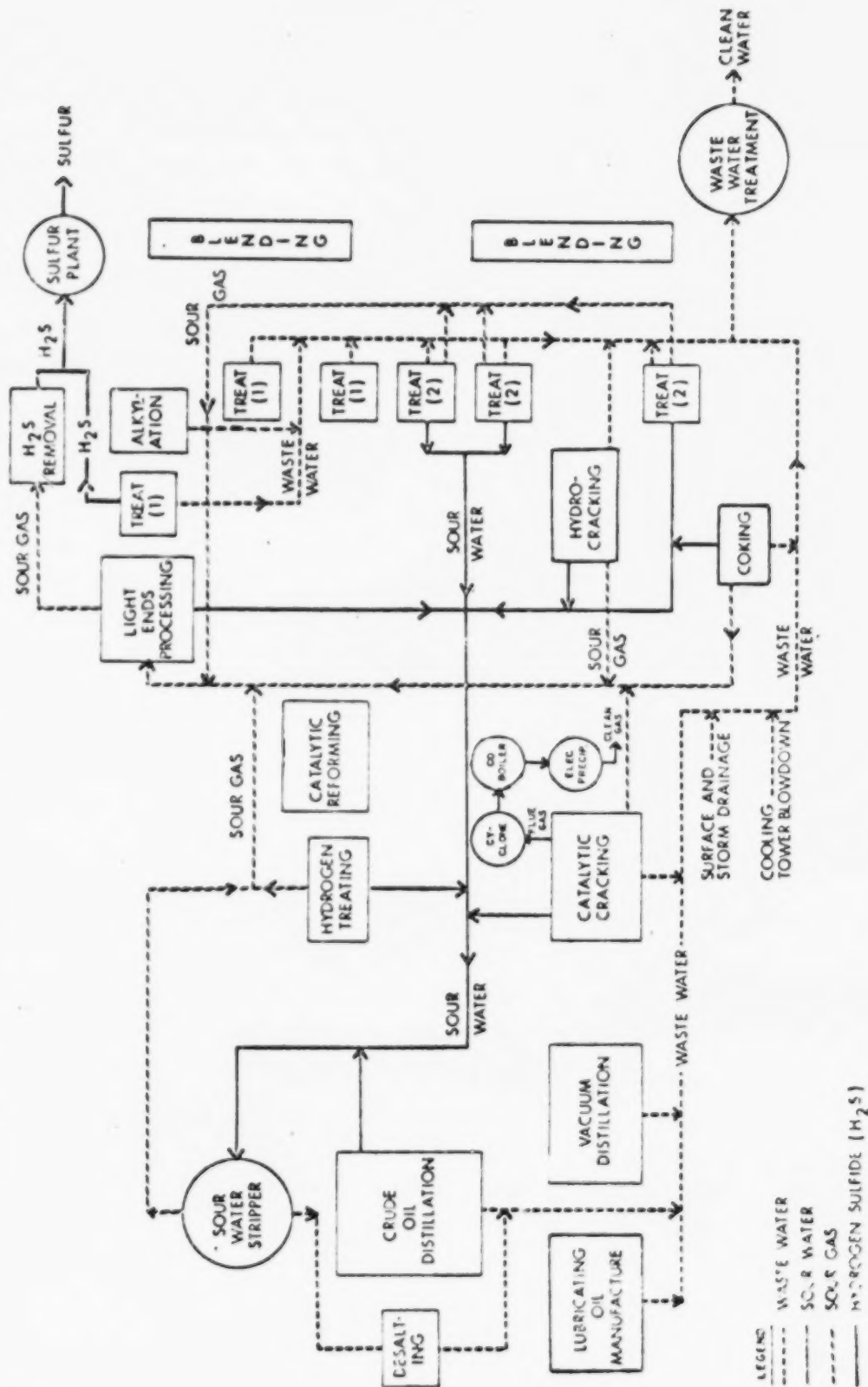
1. Centrifugal separation. The stack gas is passed through a stationary centrifugal device (cyclone) at high speed. The resultant force throws the dust to the outside wall from which it is collected.
2. Electrostatic precipitation. The stack gas is passed between metal plates which are electrically charged to a high voltage. The dust is attracted to, and settles on, the plates from which it is recovered.

Soot and fly ash. Entrained in stack gas from furnaces or boilers fired with residual, coal or coke.

1. Electrical precipitation.

SCHEMATIC FLOW DIAGRAM OF PETROLEUM REFINERY

B. POLLUTANT COLLECTION AND TREATMENT



picture is complicated by wide variations in crude oil composition and varying sulfur content restrictions. Residual desulfurization is expected to be expensive. These matters are of compelling economic importance to many refiners.

2. Type and location of raw materials.

Crude oil is the most important raw material used by the refining industry. Natural gasoline, a liquid product of the natural gas industry, furnishes about 5 percent of refinery intakes. Butanes contribute about 1.5 percent of refinery intake. There are no other significant raw materials. About 73 percent of industry raw material is of domestic origin; 27 percent is imported.¹⁾ The imports originate in Canada, South America (largely Venezuela), Africa, Indonesia, and the Middle East. Because Canada has plans to eliminate exports to the U.S. and Venezuela production appears to have topped out, an increasing fraction of imports is likely to come from the Middle East.

The major crude-producing states are Texas, Louisiana, California, Oklahoma, Wyoming and New Mexico, although 30 of the 50 states have some production. Texas and Louisiana together account for about two-thirds of the domestic industry's crude oil production. Large Alaskan deposits will be exploited when a transportation system for them is completed.

Because most refining is done by firms who also produce crude oil, a large fraction (roughly 60%) of crude used by refiners is not purchased by refiners. But, in order to

1) U.S. Bureau of Mines, Mineral Industry Surveys - Crude Petroleum, August 1974.

minimize transportation and other costs, there exists a well developed crude oil exchange system. As a result, crude oil produced by one company is most likely to be processed by another. In addition to using own produced (and exchanged) crude oil, refiners also purchase both domestic and foreign crude oil on a spot and contract basis.

3. Number and location of firms and of plants.

There are about 139 firms in the oil refining industry. They own some 277 refineries located in 40 states and 3 possessions. Refinery locations are concentrated along the Mississippi-Louisiana-Texas Gulf Coast; near Los Angeles, Bakersfield, and San Francisco; in the Pacific northwest; near Chicago, St. Louis, and Detroit; near Philadelphia, and in New Jersey; in Appalachia; and in Oklahoma-Kansas. Refineries are also located in Guam, the Hawaiian Foreign Trade Zone, Puerto Rico, and the Virgin Islands.

4. Types of firms.

Firms in the oil refining industry can be classified according to size, extent of integration with crude oil production and marketing, and the number and size of refineries owned. All refineries are necessarily multi-product and all perform the entire process of converting crude oil into salable products. Most large- and medium-size firms, and some small ones, have diversified into chemical manufacturing. Very few have further diversified into other industries. The fraction of total capital employed in non-oil or chemical activities generally is small, but is rapidly growing and taking on increased significance in a few firms.

5. Types of plants.

Oil refineries are categorized by size and by the range of their products. There is also considerable variation in age of refineries. But classification by age of initial operations is not useful because additions to and modifications of plants are the industry's principal form of expansion.

Exhibit 7 shows the distribution of refineries by size as of December 1, 1974. Refineries of over 100,000 barrels per day capacity account for about 61 percent of U.S. refinery capacity (a barrel is 42 U.S. gallons). About 17 percent, or 47 of the total of 277 plants, are in this size group. Very few new refineries have been built in the last seven years and few have been abandoned. Of a total population of 273 seven years ago, 4 have been merged into other plants, 36 appear to have been shut down, 41 new and/or reactivated plants have been added. As a result of the Federal Energy Administration's mandatory allocation regulations, the data base has been expanded to include 3 refineries in Guam, the Hawaiian Foreign Trade Zone, and the Virgin Islands, as well as the 3 refineries in Puerto Rico.

Exhibits 8 and 9 show the distribution by size of refineries on January 1, 1968, and January 1, 1974. Exhibits 9A and 9B compare the refineries in operation on these dates by size classes and by total refining capacity. Exhibits 10 and 11 show the refinery shut-downs and new/or reactivated additions in the past seven years. Exhibits 11A and 11B compare the shut-downs and additions over the past seven years by refinery size class and by total capacity. The recently-built plants, which appear to be fairly complete refineries, vary in size from 10,000 to over 150,000 barrels

Exhibit 7

Refineries
Distribution By Size
12/1/74

Refinery Capacity 1000 B/CD	Refineries			Capacity		
	No.	Per- Cent Of Total	Cum. Per- Cent	1000 B/CD	Per- Cent Of Total	Cum. Per- Cent
Below 4.0	36	13.0		70.6	0.4	0.4
4 to 6.9	31	11.2	24.2	157.7	1.0	1.4
7 to 14.9	38	13.7	37.9	382.3	2.4	3.8
Median (26)			50			8.1
15 to 29.9	46	16.6	54.5	1015.6	6.4	10.2
30 to 49.9	38	13.7	68.2	1,598.0	10.1	20.3
50 to 69.9	19	6.9	75.1	1,121.5	7.1	27.4
70 to 99.9	22	7.9	83.0	1,863.0	11.8	39.2
100 to 199.9	32	11.6	94.6	4,525.0	28.6	67.8
200 and up	15 ¹⁾	5.4	100.0	5,092.1 ¹⁾	32.2	100.0
TOTAL	277	100.0		15,825.8	100.0	

Source: NPRA Compilation of Statistics reported by refiners to FEA Office of Crude Oil, Refinery Yield, and Petrochemical Feedstocks for the Allocation Quarter Commencing December 1, 1974. Refineries in Guam and Virgin Islands included.

Note: Total includes - 271 refineries in U.S.
 3 refineries in Puerto Rico
 1 refinery in Hawaiian Foreign Trade Zone
 1 refinery in Guam
 1 refinery in Virgin Islands

277 Total

¹⁾ The FEA statistics for U.S. refinery capacity as of 12/1/74 indicate the Atlantic Richfield refinery at Houston to be 187,500 barrels per day while the BOM statistics for 1/1/74 and 1/1/75 indicate 213,000.

Exhibit 8

Refineries
Distribution By Size
1/1/68

Refinery Capacity 1000 B/CD	Refineries			Capacity		
	No.	Per- Cent Of Total	Cum. Per- Cent	1000 B/CD	Per- Cent Of Total	Cum. Per- Cent
Below 4.0	56	20.5		113	1.0	
4 to 6.9	30	11.0	31.5	153	1.4	2.4
7 to 14.9	33	12.1	43.6	337	3.0	5.4
Median (20)			50			8.1
15 to 29.9	45	16.5	60.1	953	8.4	13.8
30 to 49.9	40	14.6	74.7	1,551	13.7	27.5
50 to 69.9	19	7.0	81.7	1,121	9.9	37.4
70 to 99.9	19	7.0	88.7	1,583	13.9	51.3
100 to 199.9	23	8.4	97.1	3,210	28.3	79.6
200 and up	<u>8</u>	<u>2.9</u>	<u>100.0</u>	<u>2,324</u>	<u>20.4</u>	<u>100.0</u>
TOTAL	273	100.0		11,345	100.0	

Source: Bureau of Mines Mineral Industry Surveys, "Petroleum Refineries in the United States and Puerto Rico," August 16, 1968, with minor adjustments.

Note: Total includes - 271 refineries in U.S.
2 refineries in Puerto Rico

273 Total

Exhibit 9

Refineries
Distribution By Size
1/1/74

Refinery Capacity 1000 B/CD	Refineries			Capacity		
	No.	Per- Cent Of Total	Cum. Per- Cent	1000 B/CD	Per- Cent Of Total	Cum. Per- Cent
Below 4.0	37	14.0		73	0.5	
4 to 6.9	31	11.7	25.7	152	1.0	1.5
7 to 14.9	33	12.5	38.2	345	2.3	3.8
Median (27)						8.1
15 to 29.9	44	16.6	54.8	994	6.6	10.4
30 to 49.9	31	11.7	66.5	1,260	8.4	18.8
50 to 69.9	18	6.8	73.3	1,036	6.9	25.7
70 to 99.9	25	9.4	82.7	2,086	13.9	39.6
100 to 199.9	30	11.3	94.0	4,074	27.1	66.7
200 and up	<u>16</u>	<u>6.0</u>	<u>100.0</u>	<u>4,996</u>	<u>33.3</u>	<u>100.0</u>
TOTAL	265	100.0		15,016	100.0	

Source: Bureau of Mines Mineral Industry Surveys, "Petroleum Refineries in the United States and Puerto Rico," July 22, 1974, with minor adjustments.

Note: Total includes - 259 refineries in U.S.
 3 refineries in Puerto Rico
 1 refinery in Hawaiian Foreign Trade Zone
 1 refinery in Guam
 1 refinery in Virgin Islands

265 Total

Exhibit 9A
 Number of Refineries
 By Size Classes
 1968 - 1974

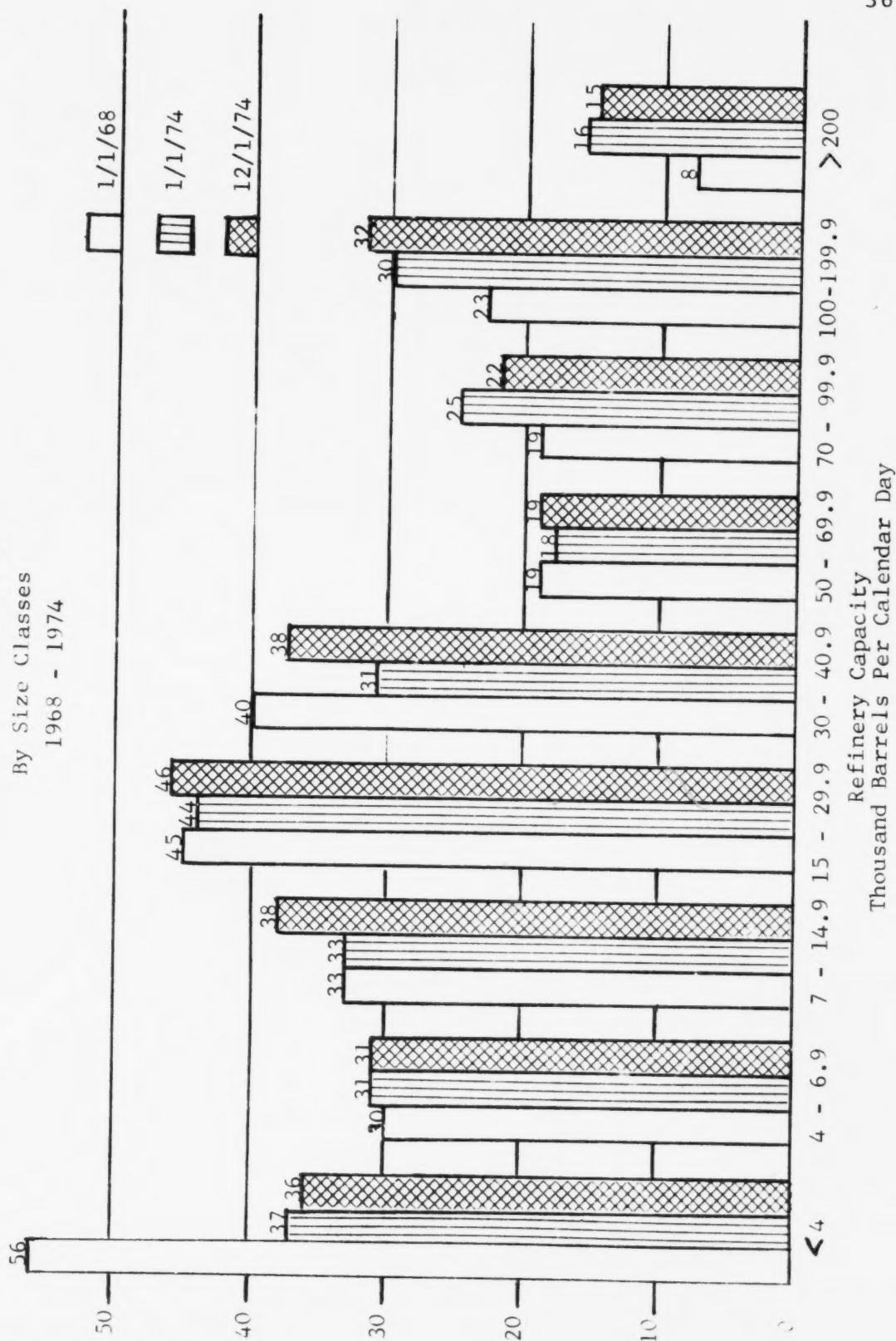


Exhibit 9B
Refinery Capacity
By Size Class
1968 - 1974

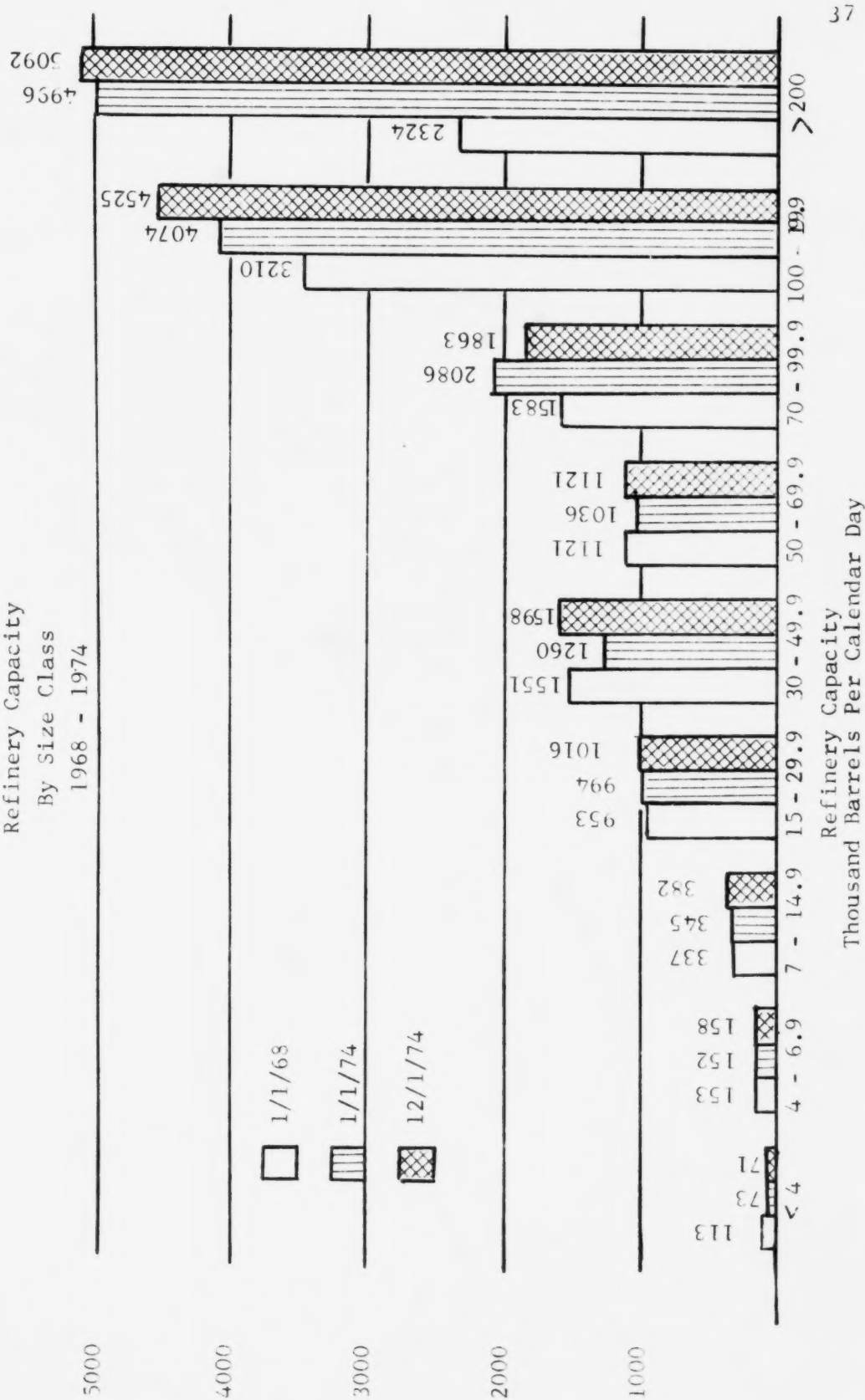


Exhibit 10

Refinery Shut-Downs
1/1/68 to 12/1/74

Refinery Capacity 1000 B/CD	Refineries			Capacity		
	No.	Per- Cent Of Total	Cum. Per- Cent	1000 B/CD	Per- Cent Of Total	Cum. Per- Cent
Below 4.0	15	41.7		22.6	3.9	
Median (6.0)			50.0			5.1
4.0 to 6.9	4	11.1	52.8	21.5	3.7	7.6
7.0 to 14.9	6	16.7	69.5	65.4	11.3	18.9
15.0 to 29.9	1	2.7	72.2	24.0	4.1	23.0
30.0 to 49.9	6	16.7	98.9	218.1	37.6	60.6
50.0 to 69.9	<u>4</u>	<u>11.1</u>	<u>100.0</u>	<u>228.9</u>	<u>39.4</u>	<u>100.0</u>
TOTAL	36	100.0		580.5	100.0	

Source: Bureau of Mines Mineral Industry Surveys, January 1968,
and FEA Allocation Statistics December 1, 1974.

Note: All refineries located in United States

Exhibit 11

New or Reactivated Refinery Additions
United States, Puerto Rico, ~~Guam, Hawaiian~~ FTZ, Virgin Islands

1/1/68 to 12/1/74

Refinery Capacity 1000 B/CD	Refineries			Capacity		
	No.	Per- Cent Of Total	Cum. Per- Cent	1000 B/CD	Per- Cent Of Total	Cum. Per- Cent
Below 4.0	14	31.8		21.5	1.2	
4 to 6.9	5	11.3	43.1	25.4	1.5	2.7
Median (9.0)			50.0			4.1
7 to 14.9	9	20.4	63.5	89.6	5.2	7.9
15 to 29.9	5	11.4	74.9	102.5	5.9	13.8
30 to 49.9	4	9.1	84.0	141.6	8.1	21.9
50 to 69.9	1	2.2	86.3	54.8	3.1	25.0
70 to 99.9	3	6.8	93.1	269.0	15.4	40.4
100 to 199.9	2	4.6	97.7	340.1	19.5	59.9
200 and up	<u>1</u>	<u>2.3</u>	<u>100.0</u>	<u>700.0</u>	<u>40.1</u>	<u>100.0</u>
TOTAL	44	100.0		1,744.5	100.0	

Source: Bureau of Mines Mineral Industry Surveys, January 1968,
and FEA Allocation Statistics December 1, 1974.

Note: Total includes - 40 refineries in U.S.
 1 refinery in Puerto Rico
 1 refinery in Guam
 1 refinery in Hawaiian Foreign Trade Zone
 1 refinery in Virgin Islands

44 Total

Exhibit 11A
 Number of Refineries Additions & Shut-Downs
 By Refinery Size Class
 1/1968 - 12/1974

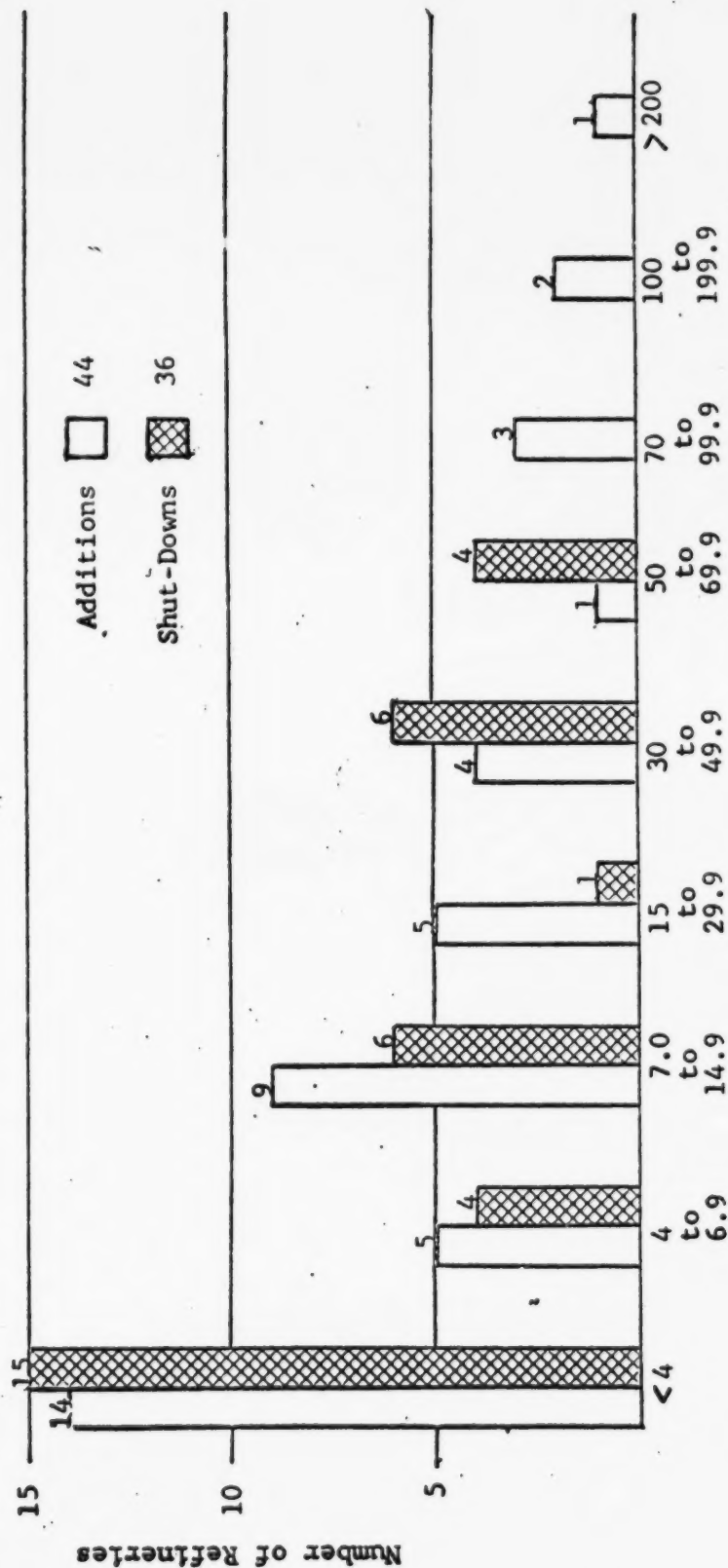
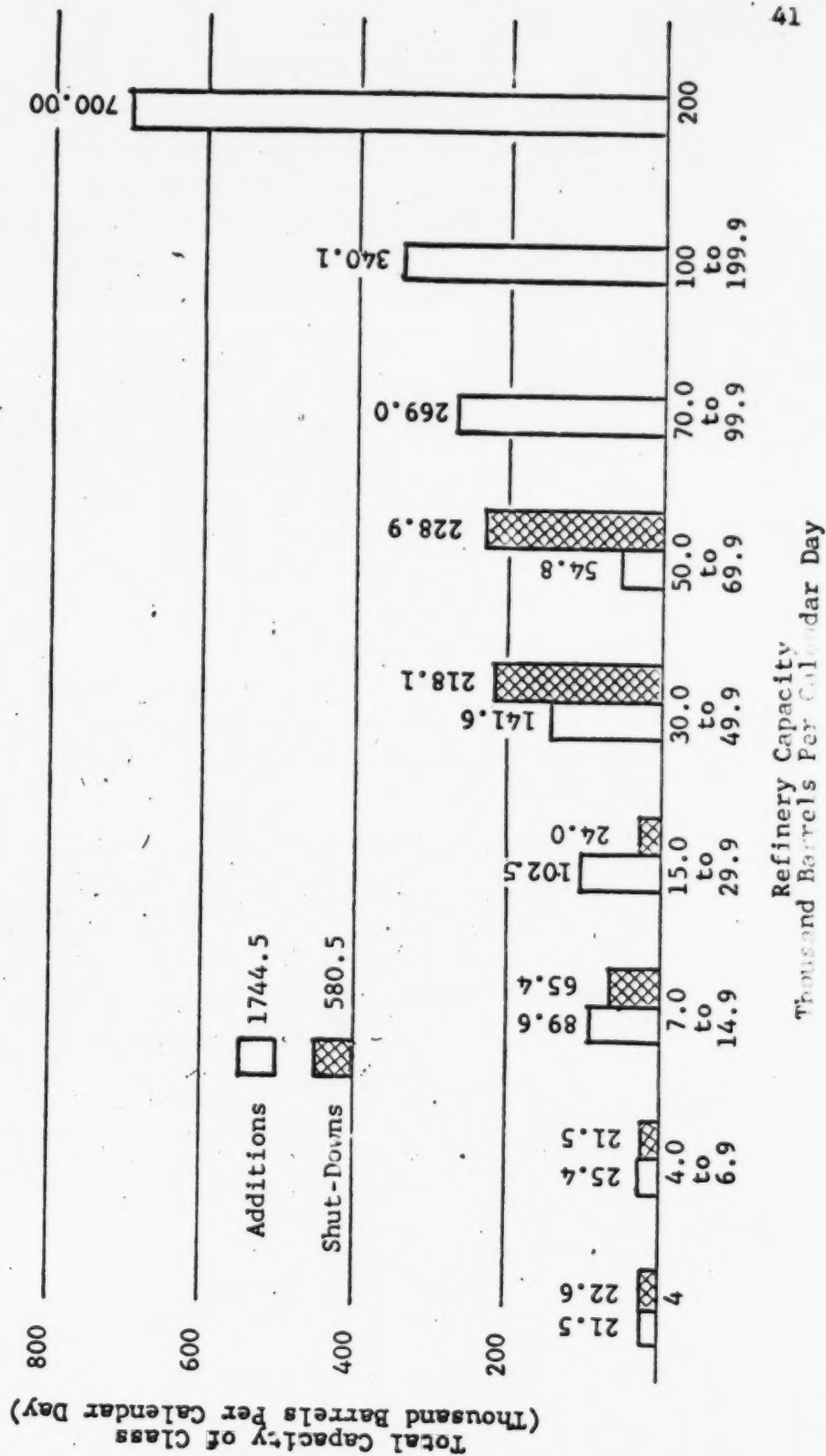


Exhibit 11B
 Additions & Shut-Downs In Refinery Capacity
 By Size Class
 1/1968 - 12/1974



per day of throughput. It appears that size is not a characteristic which in itself accounts for turnover. Certain firms have realigned the geographical pattern of their refining operations and have offset shut-downs of relatively large refineries with either new refineries or extensive expansions of others.

The 41 new or reactivated refineries in the U.S. and Puerto Rico (Exhibit 12) added in the last seven years had a total capacity of 960,000 barrels per day and the median size was 7500 barrels per day. However, 21 of them, with a capacity of about 165,000 barrels per day, have been added since 1973, and some of them undoubtedly are old refineries which were shut down, but have now been reactivated, following the establishment of the FEA mandatory crude oil allocation program. This program is designed not only to allocate the supply of both domestic and imported foreign crude oil, but to distribute as well the supply of lower-cost, price-controlled domestic crude oil.

Multiple plant operations are commonplace in the industry. As of December 1, 1974, the 19 largest firms, each of which has a capacity of over 200,000 barrels per day, operated 111 refineries. These 111 plants accounted for 79 percent of the industry's capacity, even though 16 of them had capacities of less than 26,000 barrels per day. Half of all industry refineries (138 plants) are smaller than 26,000 barrels per day. They account for only 8 percent of industry capacity. (Exhibit 7).

Exhibit 12

New or Reactivated Refinery Additions

United States, Puerto Rico, Guam, Hawaiian FTZ, Virgin Islands

1/1/68 to 12/1/74

Refinery Capacity 1000 B/CD	Refineries			Capacity		
	No.	Per- Cent Of Total	Cum. Per- Cent	1000 B/CD	Per- Cent Of Total	Cum. Per- Cent
Below 4.0	14	34.2		21.5	2.2	
4 to 6.9	5	12.2	46.4	25.4	2.7	4.9
Median (7.5)						6.5
7 to 14.9	9	22.0	68.4	89.6	9.3	14.2
15 to 29.9	4	9.7	78.1	73.0	7.6	21.8
30 to 49.9	4	9.7	87.8	141.6	14.8	36.6
50 to 69.9	0			-		
70 to 99.9	3	7.3	95.1	269.0	28.0	64.6
100 to 199.9	2	4.9	100.0	340.1	35.4	100.0
200 and up	0			-		
TOTAL	41	100.0		960.2	100.0	

Source: Bureau of Mines Mineral Industry Surveys, January 1968,
and FEA Allocation Statistics December 1, 1974.

Note: Total includes - 40 refineries in U.S.
1 refinery in Puerto Rico

41 Total

A large number of these smaller refineries are located within isolated crude producing areas or near small markets far from alternate product supply sources. However, these refineries are generally near crude supplies, either from the ground or near crude oil pipelines, and they serve local, moderately-sized marketing areas.

Technological progress in the past 20 years has induced construction of larger, lower-unit-cost process units. Consequently, there has been a trend toward larger plants. No new grassroot plants of over 200,000 barrels per day have been built. Rather, the industry's net growth in capacity has been the result of plant expansion within, and to, this very large-size class. In the last several years, quite a few large new refinery projects were announced and subsequently cancelled. One large new plant of about 200,000 barrels per day capacity is now under construction, and two or three smaller refineries have recently been built.

The trends in the industry most significant to this study are that the number of refineries has remained constant but their average size has increased. As mentioned previously, a large number of the new and reactivated small capacity plants are viable only as a result of the Federal crude oil allocation program.

In general, very small refineries with intakes below about 10,000 barrels per day have few processing units and manufacture only a narrow range of products. Some small refineries in Pennsylvania, southern Arkansas, Oklahoma, and south Texas take advantage of local crude quality to manufacture lubricants.

Asphalt is also an important product for many small refineries. It is costly to transport, especially overland. A relatively large fraction of the industry's asphalt output is produced in small refineries, and over a third of the plants with capacities below 10,000 barrels per day produce asphalt as a principal product.

As regards refinery differentiation by product slate, many small refineries are designed to process crude oil (often low-sulfur) into the naturally occurring portions of gasoline, intermediates and residual, or asphalt which is essentially a special grade of residual. Such a refinery requires only a crude oil distillation unit, a catalytic reformer with feed pretreater (if gasoline is manufactured), two or three additional distillation columns and treating units. Some small refiners in southern California, due to the characteristics of local crude oil, manufacture military jet fuel and residual with a crude oil unit only. On the other hand, a large refinery, manufacturing a full range of fuel products, plus lubricants, industrial solvents, liquefied petroleum gas, and a few common chemicals, will have a score or more of process units.

A common technology is used throughout the industry. The differences that do exist are small and probably not significant in terms of a plant's ability to meet environmental standards economically. There are important differences in the extent to which environmental control equipment has been installed to date. This will be discussed in Part II of this study.

6. Employees

Data on employment and earnings are presented in Exhibit 13. About 60 percent of petroleum refining employees

are production workers. Their hourly and weekly earnings are considerably above the average for all manufacturing. Hourly earnings of production workers in 1973 in petroleum refining were estimated at \$5.54 versus \$4.07 for all manufacturing.

Refinery employment as a whole has been fairly stable. In 1964, there were 150,000 employees and in 1973, 147,000.

Perhaps one-third of refining industry employees have skills which are not readily transferable to other industries. While it was beyond the scope of this study to make a detailed analysis of the transferability of the skills required by the industry, an examination of the occupational titles indicates that two-thirds of the employees have skills which are not special to the industry, or they are unskilled.

Detailed occupational data for the petroleum refining industry are available for the year 1971. In that year, 153,000 people were employed in the petroleum refining industry, 90,000 of whom were production workers. These figures include employment in central offices, research laboratories, etc. of refining firms as well as in refineries. Refinery employment itself was about 98,000, including about 70,000 production workers. A Bureau of Labor Statistics study¹⁾ of a representative sample of 50,000 of the 70,000 showed that almost one-third of refinery production workers were maintenance workers and 85 percent of these were skilled craftsmen, such as welders, mechanics, machinists, electricians, etc. One-half of production workers were skilled refinery operators, such

1) Industry Wage Survey, Petroleum Refining, April 1971, Bulletin No. 1741, U.S. Department of Labor. Bureau of Labor Statistics, p. 12.

Exhibit 13

EMPLOYMENT, EARNINGS AND PAYROLLS
IN PETROLEUM REFINING, 1964-1973

	Total Number of Employees ²⁾ (Thousands)	Production and Related Workers ¹⁾			
		Number of Workers (Thousands)	Average Weekly Earnings	Average Hours Worked Weekly	Average Hourly Earnings
1973	147	89	\$231.02	41.7	\$5.54
1972	151	89	219.45	41.8	5.25
1970	154	90	189.93	42.3	4.49
1968	151	92	166.27	42.2	3.94
1966	148	89	151.56	42.1	3.60
1964	150	90	139.52	41.4	3.37

1) Includes non-salaried workers.

2) Includes both salaried and non-salaried employees.

Source: Bureau of Labor Statistics, "Employment and Earnings."
Reprinted in Petroleum Industry Statistics 1964/73,
American Petroleum Institute, September 1974, p. 50.

as stillmen, treaters, compounders, testers, etc. These men's skills are probably transferable only to other similar industries, such as chemical manufacturing or food processing. The balance of the production workers are either unskilled, or are helpers or have general skills such as stock clerks or truck drivers.

Thus, it appears that about one-third of the people in the industry (probably a smaller fraction in small plants that purchase laboratory and some maintenance services from outside contractors) are skilled workers whose job opportunities at a comparable skill level are dependent on reemployment in the "process" industries. The other two-thirds are employable in other industries at their present skill levels if job opportunities exist for them.

Recent changes in refinery labor utilization include a trend to increased use of "contract maintenance" and the classification of operating labor as "staff" rather than "hourly." These changes tend to reduce labor transferability to other industries but improve productivity in refineries.

B. Financial Structure and Trends

It is impossible to analyze the financial structure of the petroleum refining industry using published data. Too few firms, and none that are typical of the industry, are exclusively or even primarily in the refining business. To discuss the financial characteristics of the industry, price data will be used which reasonably reflect the values of products made by typical refiners, and the cost data considered appropriate for crude oil will be estimated based on experience.

1. Costs - fixed and variable.

No data are published which break down refinery costs in a manner useable for this study. An estimate has

therefore, been made for a plant manufacturing fuel products (no lubricants). The reader is cautioned that no actual refinery will exactly match these figures. Refining costs are characterized by a very high ratio of raw material costs to total costs. Fixed costs make up most of the balance. The illustrative estimate of costs follows:

Costs - Fixed and Variable (1974 prices)

<u>Item</u>	<u>Cost/Barrel of Refinery Intake</u>	<u>Percent of Total Costs</u>	
		<u>Fixed</u>	<u>Variable</u>
Raw Materials (Average)	\$ 9.30		76%
Fuel and Utilities	.90	1%	6%
Labor	.35	3%	
Chemicals, Catalysts, Additives & Materials	.35		3%
Insurance and Taxes	.10	1%	
Capital Recovery	<u>1.20</u>	<u>10%</u>	<u>—</u>
TOTAL	\$ 12.20 ¹⁾	15%	85%

2. Profits.

No data on refinery profitability are available. But it is reasonable to assume that in the absence of price controls or product allocations, refining operations are, on the margin, neither more nor less profitable than the rest of a typical oil company's business.²⁾ The effect of price controls on refining profitability cannot be ascertained. Exhibit 14 gives some relevant financial data for the oil industry.

1) Equivalent to about 29 cents per gallon of salable product.

2) In the absence of this equality prudent oil company's managers would re-allocate investments until the equality is re-established.

Exhibit 14

RATE OF RETURN ON NET WORTH FOR PETROLEUM,
MANUFACTURING, AND ALL INDUSTRY
IN THE U.S., 1964-1972

<u>Year</u>	<u>Petroleum Industry</u>	<u>All Manufacturing Industry</u>	<u>All Industry</u>
1972	10.8	12.1	10.5
1971	11.2	10.8	9.7
1970	11.0	10.1	9.0
1969	11.9	12.4	10.3
1968	13.1	13.3	10.8
1967	12.8	12.6	10.6
1966	12.6	14.2	11.3
1965	11.9	13.9	11.1
1964	11.5	12.6	10.3

Source: First National City Bank, "Monthly Economic Letter,"
May, 1973.

While profitability of the business as a whole has been subject to some variability, industry earnings have been adequate to attract capital to finance growth and replacement.

3. Cash flows.

Due to the uncertainties about future demands which were discussed earlier in this report, it is impractical to make a detailed estimate of the refining industry's capital requirements for expansion and plant modernization in the years to come. But a recapitulation of industry plans (which are subject to change) is shown in Part II of this study. In 1973, the thirty largest petroleum companies invested about \$1.3 billion in refineries and chemical plants¹⁾ in the U.S. If normal growth rates were to prevail, then capital expenditures on these plants in the next 10 years would be about \$15 to \$20 billion. But energy conservation measures, as well as the recent increases in crude oil prices, may depress capital requirements. But if government provides incentives to decrease dependence on foreign sources of products there may be an increase in capital investments.

It is useful to put the estimates of capital requirements for refineries in perspective with oil company capital expenditures for all purposes. Data on a group of 30 large oil companies show that roughly 17 percent (about \$1.3 billion of \$7.6 billion) of domestic capital expenditures by this group represents investment in refineries and chemical plants in 1973.²⁾ Total domestic investment in that year for the same group of companies is about 52 percent of world-wide investment.³⁾

1) The Chase Manhattan Bank, N.A., Financial Analysis of a Group of Petroleum Companies, 1973, p. 29.

2) Ibid., p. 29.

3) Ibid., p. 18.

C. Refinery Technology and Technological Trends.

Petroleum refining has been a high-technology industry since World War I. The technology of the industry has steadily improved. During the last 30 years a few major breakthroughs, notably catalytic cracking, alkylation, hydrocracking, catalytic reforming, hydrotreating, and several new lubricating oil manufacturing processes, have had profound effects. Similarly new chemical manufacturing processes have broadened the range of refinery products substantially. But of almost equal importance in the long run has been the improvement in existing processes. Technological improvements are utilized industry-wide because industry members traditionally license the use of significant new technology to competitors. There are no important trade secrets in the refining industry.

A combination of product quality competition and economies of building and operating larger plants has served to push oil refining firms toward bigger and more complex refineries. Product quality competition has been achieved by the use of additives and of quality-improving processes like catalytic reforming to increase gasoline octane number, and by catalytic hydrogen treatment to reduce sulfur content of intermediates. This has led to an increase in the amount and value of processing equipment per unit of output. Relatively low residual prices, which have encouraged investment to reduce residual yields, also raise the value of equipment per unit of output. Recent changes in import policies allow domestic residual oil to be priced competitively with other domestic products. Consequently, some recent refinery expansions, and the one large new plant under construction, no longer emphasize the minimization of residual yields.

Thus, larger refineries and larger units within existing refineries and increasing integration of the many process steps into a network mark the industry's development. Once the possibility exists to build and operate larger plants, there will be a strong economic incentive to do so. Large plants cost less to build per unit of intake than smaller ones. Typically, it only costs about 65 percent more to build a plant with 100 percent more capacity (the "two-thirds power rule").

This does not mean that an existing small plant is necessarily unviable. Existing small plants can often be effective competitors. But typically, new small plants are only being built for local, special marketing conditions. Reactivation of old refineries or modifications of existing facilities which have not previously been called crude oil refineries are taking place so that the owners of these plants may secure allocations to purchase price-controlled crude oil from FEA.

D. Industry Utilization Rates.

It is important to differentiate between a refinery's capacity to process crude oil and its capacity to manufacture a particular product. Almost all refineries have the flexibility to alter their product mix. They can to some extent increase the output of gasoline at the expense of intermediates, or they can produce more intermediates at the expense of gasoline. Nearly all refineries could increase residual manufacture above the design level. Published data on capacity utilization cannot reflect the industry's ability to alter yields or adjust crude slates. Hence, they are not useful in estimating the industry's ability to increase output of specific products.

Requirements to manufacture products with specific properties further influence capacity. For example, a refinery that can manufacture a given quantity of 94 octane leaded gasoline might be able to make only 70 percent of that quantity of lead-free 94 octane, with the same equipment.

Producing low-sulfur residual also presents special problems. In the U.S., residual has been essentially a by-product of the refining process.¹⁾ Its sulfur content was predominately dependent on the sulfur content of the crude the refinery uses. It follows that most refineries have no "capacity" to produce low-sulfur residual from a high-sulfur crude stream. Some desulfurizing capacity is now being installed.

Availability of fuel of acceptable quality for internal refinery use also affects refinery capacity. In their internal operations refiners normally burn the lowest-valued material available. They first use the gases produced as a by-product of refining operations because these gases generally have no market. The next choice is purchased natural gas, if available, because it is priced below liquid fuels (per BTU) in most parts of the U.S., and the facilities needed to burn gas are cheaper than those needed to burn liquids. A small amount of coal is also used in Pennsylvania and West Virginia. The remaining requirement, currently about 135,000 barrels a day,²⁾ is met largely with residual fuel. Residual and coal frequently contain considerable sulfur.

Similarly, the availability of gas in some instances affects capacity. Refineries with no facilities for burning

1) In the rest of the world this product is an important refinery outturn and is called heavy fuel oil.

2) Mineral Industry Surveys, op. cit., April, 1974.

liquid or solid fuels would have to install new equipment if gas were not available in sufficient quantity. This would be expensive as well as requiring time to convert.

E. Competition.

Were it not for price controls, the domestic market for wholesale oil products would be competitive in the economist's meaning of the term. That is, the price elasticity of demand facing individual firms would be high. Despite a strong and continuing industry effort to establish brand differentiation for retail consumers, the wholesale market operates on a commodity basis. Perhaps one-third of gasoline,¹⁾ about 50 percent of intermediates, and almost all residuals are sold as commodities. With such large volumes sold by many refiners, an active brokerage business exists. Non-brand marketers maintain aggressive purchasing staffs, and oil companies compete vigorously on various "bid" markets.

Prices on the various unbranded markets typically are close to short-run marginal costs. This indicates that the industry is highly competitive. The normal competitive nature of the refining industry would affect its ability to pass cost increases on to consumers in the short run. But with price controls and allocations, normal market forces do not necessarily determine prices, product distribution or profitability.

Prior to 1972, foreign crude oil was less expensive than domestic. Although the domestic price was protected by an import quota, production failed to keep pace with demand. In mid-1973, prices became equal, due to the success of the oil cartel (Organization of Petroleum Exporting Countries). Price controls have been in effect

¹⁾ So-called unbranded sales at retail by independent oil companies, commercial sales direct to users and sales to government aggregate to somewhat over 50 percent of total gasoline sales.

on domestic products most of the time since 1971. In 1972 the Executive branch of government announced a program to encourage domestic production and refining by imposition of a tariff system. This program's legality has been challenged in court on grounds that tariff protection can only be granted by the Congress.

Prior to the oil embargo, the industry was in transition from a quota system to a tariff system via a price control system. As a result of domestic price control, a significant disparity between world and average domestic prices now exists. And the combination of a two-price (new and old crude oil) market, with a system of entitlements to purchase "old", lower-priced, crude oil, makes it impossible to generalize about current market conditions. The price control system is slated to terminate in less than four years. Consequently, projections made in this study are made on the assumption that normal competitive market forces will prevail by the end of the period under study (about 1983).

APPENDIX

GROWTH IN REFINING CAPACITY 1968-1975

On the basis of Bureau of Mines and Federal Energy Administration statistics, the changes in refinery population and capacity that have occurred in the almost seven-year period from January 1, 1968, to December 1, 1974, have been analyzed and summarized in Exhibit 15.

From a total refinery population of 273,¹⁾ 36 refineries operating in 1968 which had ceased operating by December 1, 1974,²⁾ were identified. Of these, 27 apparently made fuel products and the remaining 9 were primarily asphalt plants and lube plants.

The viability of an asphalt refinery is greatly dependent on the local asphalt market, and a reduced local demand may be met more economically by shipment of product into the area. In addition, some asphalt plants are shut down during the winter months; hence, some of the reported shut-downs may be seasonal in nature. All of the asphalt plants which were reported closed, with one exception, were very small.

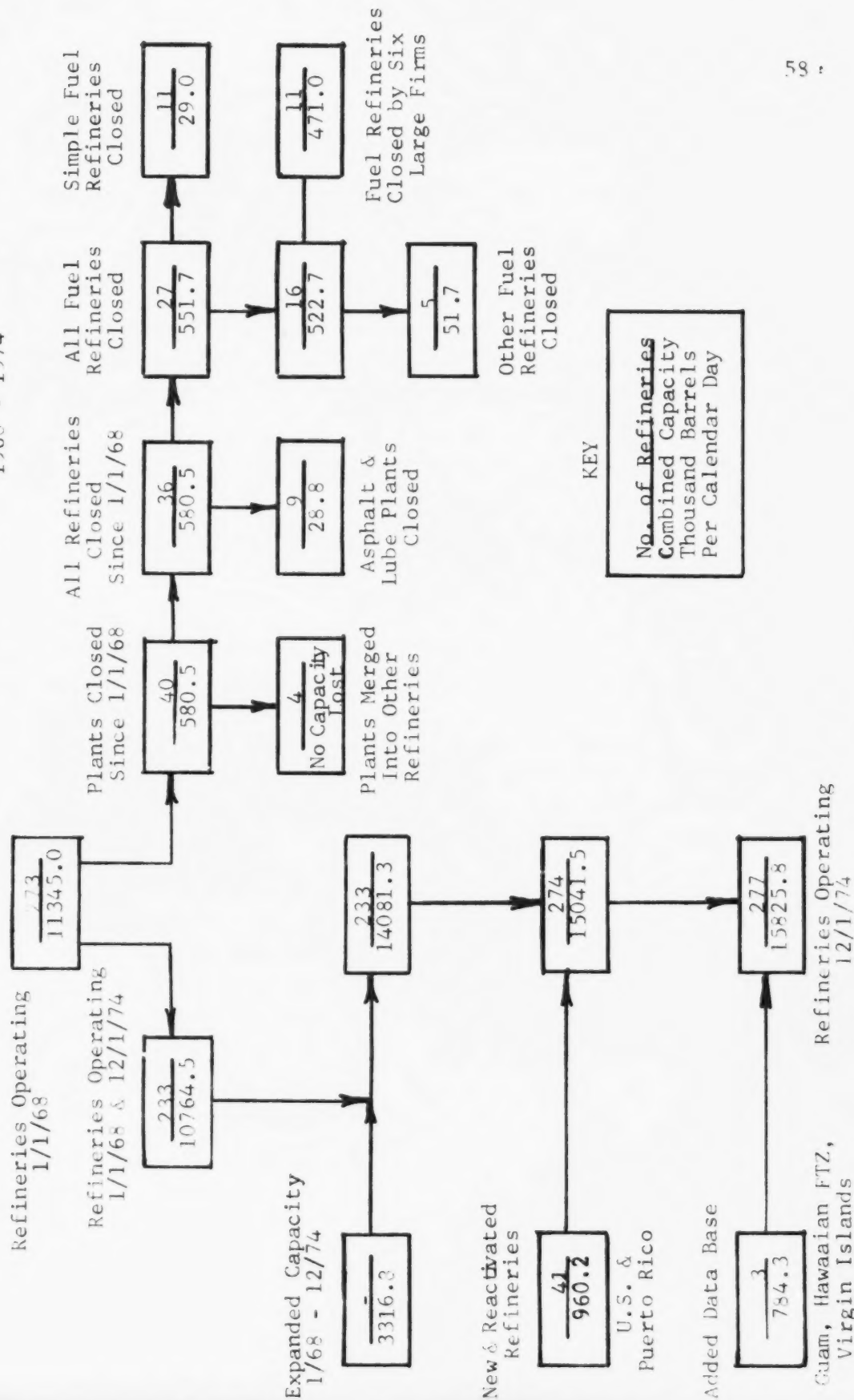
Of the 27 fuel-producing refineries, 11 reported no equipment except a crude distillation unit. Of the other 16, 11 refineries, owned by 6 different companies, were closed as a result of realignment of the geographical pattern of the refining operations of these firms, and were offset by

1) Mineral Industry Surveys-U.S. Department of the Interior-Bureau of Mines, Petroleum Refineries in the United States/ Puerto Rico, January 1, 1968, August 16, 1968.

2) As reflected from The National Petroleum Refiners Association's Compilation of Statistics reported by refiners for the allocation quarter commencing December 1, 1974, from the FEA's Office of Crude Oil, Refinery Yields and Petrochemical Feedstocks.

EXHIBIT 15

Growth of Refining Capacity and Changes in Numbers of Refineries 1968 - 1974



expansions of other plants owned by the same firm. These refineries tended to be the larger of the group of closed plants, and all but one exceeded the median U.S. refinery size of 26,000 barrels per day. Several were located in metropolitan areas, and the closure of some of these could have been instigated by land and/or zoning limitations.

Deducting these 11 plants, there remained a group of 5 fuel-producing refineries which were closed in the seven-year period. The largest of them had a throughput of 14,000 barrels per day. Their total was 51,700 barrels throughput per day. These 5 refineries account for about 0.3 percent of industry capacity. The closing of 25 refineries, including 9 asphalt or lube plants in seven years, out of a population of 273 refineries, is a small percentage. Consequently, it is reasonable to conclude that small firms are, on the whole, viable business enterprises.

Of the total refinery population of 273 on January 1, 1968, 233 were still in operation on December 1, 1974. Over the seven-year interval, the capacity of these 233 refineries had been increased some 33 percent, from 10,765,000 barrels per day to 14,081,000 barrels per day.

In the U.S. and in Puerto Rico, a total of 41 new and/or reactivated refineries with a total capacity of some 960,000 barrels per day was added over the seven years. The median-size refinery added had a capacity of 7,500 barrels per day. Twenty-one refineries with a total capacity of some 166,000 barrels per day were opened or reactivated within the last two years, encouraged to some extent by the mandatory Crude Oil Allocation Program.

Also, as a result of the Federal Energy Administration's regulations, the data base has been broadened to include refineries in the Hawaiian Foreign Trade Zone, Guam, and the Virgin Islands. As of December 1, 1974, the total refinery population of 277 refineries in the U.S. and its territories has a capacity of 15,825,850 barrels per calendar day; this is an increase of some 4.5 million barrels, or about 40 percent, over the seven years (about 5 percent per year) under review.

PART TWO

INTRODUCTION

Part Two consists entirely of work done by the technical sub-contractor for this project. Included are engineering cost estimates for processes used to conform to EPA's regulations and estimates of what fraction of the industry already conforms to each of the several control requirements. These estimates underlie the analysis in Part Three where industry and competitive impacts are developed. Two supplementary tables entitled Attachment 1 and Attachment 2 are included at the end of this Part. They present data that were developed after the sub-contractor's report had been completed.

All the economic data presented in this study are based on mid-1974 costs. The technical sub-contractor assumed that petroleum raw material and product prices, where employed represent marginal 1974 levels rather than average costs which would have reflected the impact of petroleum shortages and embargo pricing experience. Marginal 1974 product prices are defined as those required to profitably produce refined products from Light Arabian crude oil acquired at an average acquisition cost of 11.75 dollars per barrel.

All capital investment data are based on U.S. Gulf Coast construction costs. To convert investment costs to an annual cost basis, the technical sub-contractor used a pre-tax annualized capital charge of 25.82 percent of the total investment. For a "typical" project cash flow pattern over time and for a "typical" corporate tax position, this level of capital charge results in about 12 percent discounted cash flow rate of return after tax.

Revenue bonds, the interest on which is not subject to Federal income tax, are used to finance a portion of the investments required by petroleum refiners as a result of EPA's

regulations. These bonds may be used to finance pollution control, but not process, facilities. They are not likely to be used for small projects nor to finance projects by firms whose capital projects are subject to abnormal risks. The "tax free" feature results from the financing method used: the bonds are issued by local governmental units, typically municipalities, with payment of interest and principal being made by the company whose effluent is being treated. No government guarantee of either interest or principal is involved.

Because the bonds' interest payments are tax exempt, the interest expense paid by the petroleum refining company is somewhat less than the rate it pays on other debts. But because these bond issues typically are somewhat smaller than the usual petroleum company issues (100 to 250 million dollars), there may be a small bloc-size premium involved.

It is easy to overstate the cost savings resulting from the use of these tax exempt bonds. They represent a debt of the benefitted company. And they reduce that company's cost of capital only to the extent that the cost of the debt portion of total capital is reduced by the fraction of total debt represented by tax-free debt. For example: suppose that the firms' debt is 1/3 of capital; that normal debt costs 9 percent before tax (4-1/2 percent after corporate tax deductions); that "tax exempt" bonds cost 6 percent before tax (3 percent after corporate tax deduction); and that exempt bonds represent 1/4 of new debt. In this case the corporate cost of capital after tax is reduced, on average, by only 1/8 of one percent as a result of the use of tax exempt bonds¹⁾. This percentage is too small to affect the estimates made in this report and falls well within the range of error in the basic cost of capital estimates.

1) $1/3 \times (4-1/2 \text{ percent} - 3 \text{ percent}) \times 1/4 = 1/8 \text{ percent.}$

In addition to basic engineering and cost estimates, the sub-contractor's report contains other information, e.g., total industry costs, relative impacts on small refiners, etc. In order to maintain its technical integrity, the report is included in its entirety.

Part Three following consists of Sobotka & Company, Inc.'s analysis and conclusions. That work rests on the cost and conformance estimates of Part Two, but incorporates a broader economic perspective and an understanding of some subtleties of this impact analysis that have developed since the sub-contractor's work was completed.

2-4

AN ANALYSIS OF THE
ECONOMIC IMPACT OF EPA'S
REGULATIONS ON THE PETROLEUM REFINING INDUSTRY

COST OF POLLUTION ABATEMENT
TECHNICAL DOCUMENTATION

EPA CONTRACT NO. 68-01-2830

June 24, 1975

PREFACE

The calculation of investment and cost impacts resulting from environmental regulation of the petroleum refining industry has been significantly affected by the major increase in petroleum prices which occurred in 1973. Few, if any, environmental facilities added prior to 1973 afforded a significant return on invested capital. However, by mid-1974 petroleum prices had essentially quadrupled. Conversion to floating-roof product tanks not only reduced airborne emission for 1974, but recovered valuable hydrocarbons and reduced the volume of \$12.75 per barrel foreign crude oil which must be purchased. Similarly, the addition of carbon monoxide boilers to fluid catalytic cracking units not only reduced emissions of carbon monoxide, but reduced the need for consumption of refinery fuel which may be costing over \$2 per million BTU's. Thus, by 1974 economic standards, many environmental expenditures result in profit-making investments for the domestic refining industry.

The dilemma for the investigator is whether to continue counting all investments as environmentally inspired and employ the new-found credits to offset annual costs or to exclude all profit-making environmental projects completely from the tabulation. The former approach results in a larger investment total and a smaller annual cost, while the latter method has the opposite effect. The most accurate approach would probably be to evaluate each individual investment and exclude from the tabulation only those that meet the industry's accepted return on investment criteria for risk investments, but such detail is clearly beyond the scope of this study.

For purposes of this portion of the study, the authors have elected to count any investments made in response to environmental regulations and properly credit recovered products and fuel savings at marginal price levels. This tends to emphasize the investment demands placed upon industry in the next few years. We believe it is the most valid approach at present since the rapid change in petroleum costs has been moderated to some extent by long-term, low-price natural gas supply contracts and uncertain energy policies. However, if the refining industry were free to make long-term investment decisions based on the industry prices that have prevailed for the past eighteen months, it is apparent that many atmospheric emission-control projects would be attractive to pursue even in the absence of environmental regulations.

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SECTION I. SUMMARY

A. Objective

This analysis has been designed to measure the costs imposed on the petroleum refining industry by Federal Environmental Protection Agency regulations affecting refinery effluent, refinery emissions to the atmosphere, and product quality restrictions. All investment and operating cost data are presented on a 1974 economic basis and represent only additions forecast for the period 1974-1983.

B. Wastewater Controls

Wastewater requirements have been defined by Best Practicable Control Technology Currently Available (BPCTCA) to be implemented by July 1, 1977, Best Available Technology Economically Achievable (BATEA) to be implemented by July 1, 1983, and Best Available Demonstrated Technology (BADT) regulations which apply to new facilities. Consideration of zero pollutant discharge which has been proposed for 1985 is specifically excluded from this analysis. Major findings indicate:

- EPA regulations will impose investment requirements of \$1.9 billion by 1977, resulting in annualized industry costs of \$744 million in that year. About 60% of the annualized costs represent fixed charges, while 40% result from direct operating expenses.
- By 1983 water effluent control investments are expected to total \$2.9 billion, imposing a cumulative cost of \$1.15 billion on the industry annually. About 75% of the total investment will be expended to improve existing refining facilities, while the balance will be associated with new refining capacity.
- The expected investment for refiners with capacity of less than 10,000 barrels per day is \$312 per daily barrel of capacity - more than twice the level forecast for large refiners.
- 1983 annual costs expressed on a unit basis are 30 cents per barrel for refiners processing 10,000 B/D or less and an average of 16 cents per barrel for plants with capacities in excess of 10,000 B/D.

C. Airborne Emission Controls

Refining industry controls of hydrocarbons, carbon monoxide, particulates and sulfur oxides have been examined in this analysis. Reg-

ulatory bases considered include not only Federal new-source performance standards, but also the estimated impact of State Implementation Plans designed to satisfy ambient air quality standards. Major findings are:

- Industry investments for control of airborne emissions will total \$740 million by 1977 and almost \$1.3 billion by the end of 1983. Hydrocarbon control accounts for 13% of the total, carbon monoxide and particulates represent 34%, and sulfur oxide recovery facilities represent the largest portion at 53%. About 65% of total investment will be associated with existing refining facilities, while the balance represents additional investment in new refining capacity.
- Annual capital charges total \$161 million in 1977 and \$280 million by 1983. However, a large part of these costs is offset by credits resulting from improved product recovery and thermal efficiency which amount to \$117 million in 1977 and \$206 million in 1983. The resulting net annual costs attributed to airborne emission control total \$44 million in 1977, rising to \$74 million in 1983.
- Investment requirements as a function of refinery size vary from \$318 per barrel for refineries with 10,000 barrels per day of capacity to \$101 per barrel for refineries with 200,000 barrels per day of capacity.
- Impact per barrel of product in 1983 will vary from a cost of 16.5 cents for refineries of 10,000 barrels capacity to a savings of 3.1 cents for 200,000-barrel refineries.

D. Product Quality Controls

Two areas of product quality restrictions were investigated for industry impact - use of lead additives in gasoline and residual fuel sulfur levels. Since lead phasedown regulations are currently under litigation, a separate analysis of that restriction was also completed. The limitations of available studies provide lead additive analysis data only for the years 1974, 1977, 1980 and 1985, and do not differentiate between investment requirements for existing facilities and those associated with new refineries. These data have been interpolated to provide 1983 data for consistency with other portions of the report to yield the following conclusions:

- Industry investment to provide unleaded gasoline and meet a lead phasedown regulation is estimated at \$1.2 billion by 1977, rising to about \$2.7 billion by 1983. If only unleaded gasoline regulations are considered, the 1977 investment is expected to total about \$400 million, rising to about \$2.2 billion in 1983.

- Annual industry costs resulting from both unleaded gasoline and lead phasedown programs will approximate \$330 million by 1977 and \$580 million by 1983. Elimination of lead phasedown will reduce annual costs of lead regulations by about \$270 million in 1977 and about \$170 million in 1983.
- Residual fuel desulfurization investments are forecast at about \$590 million by 1977, rising to \$1,100 million by 1983. The reader is cautioned to note that this may overstate near-term investment since some 1977 low-sulfur fuel demand may be satisfied by increased processing of premium-priced, low-sulfur crudes or distillate blending. However, we believe this approach leads to a correct assessment of long-term industry effects.
- Fuel desulfurization costs are expected to require a premium of about \$1.77 per barrel for 0.7 weight percent sulfur fuel and \$2.08 per barrel for 0.3 weight percent sulfur fuel compared to high-sulfur product.

E. Overall Industry Effects

The estimated impact of combined EPA pollution abatement programs on the petroleum refining industry is shown below:

	Added Investment, \$MM		Added Annual Costs, \$MM	
	1977	1983	1977	1983
Wastewater Controls	1,880	2,870	750	1,150
Airborne Emission Controls	740	1,280	44	74
Product Quality Restrictions (Includes Lead Phasedown)	1,790	3,800	620	1,110
Total	4,410	7,950	1,414	2,334

SECTION II. STUDY CRITERIA

A. Scope

The primary aim of this study is to measure the investment and operating costs which will be incurred by the petroleum refining industry as a result of the pollution abatement requirements established by the Federal Environmental Protection Agency. Specific areas of regulations which have been investigated include the following:

- Refinery wastewater effluent guidelines.
- Atmospheric emissions from refineries.
- Product quality regulations.

The base period against which all investment and operating cost tabulations are measured is calendar year 1973. Costs which have been incurred in 1973 and prior years have not been detailed in the investigation. This is not to suggest that pollution abatement efforts to date have not been formidable. Rather, those costs are a matter of history and cannot be changed by future revisions in environmental regulations. This study focuses on the 1974 through 1983 time period and will be employed to aid the Government in making decisions with respect to future environmental regulations.

B. Analytical Approach

The three major areas of pollution abatement regulations were investigated independently in this analysis. In each instance, the analytical approach conformed to the following guidelines:

1. Definition of the regulatory bases.
2. Identification of the required control technology.
3. Determination of 1973 industry capability.
4. Development of investment requirements to meet future regulatory deadlines.
5. Calculation of annualized costs of operating control equipment.
6. Allocation of investments and operating costs to various sectors of the refining industry.

The primary approach was to review published studies of pollution control techniques, investment levels and operating costs which

have been completed in the past few years under industrial or government sponsorship. The bases employed in the earlier studies were then updated to account for changes in regulatory requirements, facilities in place by 1973, changes in control technology, and new economic conditions. While no original research was conducted by the authors of this study, considerable effort was expended to insure the indicated results represent a realistic view of the costs imposed upon the petroleum refining industry. The authors visited with several representative small or independent refineries to discuss regulatory impacts, current operating and control procedures, and anticipated future pollution abatement investments. In addition, information available from previously completed proprietary studies was incorporated into analysis of control technology investments and operating costs for the entire petroleum refining industry.

The approach employed in this study should lead to a reasonably accurate assessment of the total investment and operating cost impact incurred by the petroleum refining industry. In addition, we believe that the allocation of costs to individual industry sectors offers a reasonable indication of costs to be borne by the various categories of petroleum refineries. However, we should note that the techniques employed in this study, while valid for industry characterization, cannot be expected to indicate the specific investment or operating cost impact for any individual refinery. Only detailed engineering and economic studies which are specific to an individual refinery can be expected to describe the exact investment and operating cost impact.

C. Economic Basis

All economic data presented in this study are based on mid-1974 costs. Petroleum raw material and petroleum product prices, where employed, represent marginal 1974 cost levels rather than average costs which would have reflected the impact of petroleum shortages and embargo pricing experience. Marginal 1974 product prices are defined as the estimated refinery prices which are required to allow profitable processing of Light Arabian crude acquired at FEA's reported average 1974 foreign crude acquisition cost of \$12.75 per barrel into refined products. All capital investment data are based on U.S. Gulf Coast construction costs.

In each instance, capital charges have been estimated as follows:

- 12% discounted cash flow rate of return after 50% Federal Income Tax.
- Straight-line depreciation taken over 16-year life.
- 4% allowance for insurance and ad valorem taxes.

This results in an annualized capital charge of 25.82% of the total capital investment. Some consideration was given to lower return on investment as representative of future refinery investment criteria.

Since the pollution abatement investments will be imposed uniformly across the industry, an investment of this type would normally be considered a low-risk opportunity. However, we feel it is unrealistic to expect the industry to raise significant amounts of new investment capital if the rate of return on investment even for secure facilities is any lower than 12% DCF.

D. Basic Industry Facilities

A major effort of this study has been to properly describe the impacts of pollution abatement regulations on different sectors of the petroleum refining industry. The primary features of the petroleum industry which have been employed to divide the industry into sectors are:

- Primary refined products.
- Refinery capacity.
- Raw material supply.
- Major market area.

Technical data used to define the petroleum industry facilities available for operation in the 1973 base period were adapted from the Oil & Gas Journal. These data are presented in detail on Table A-1 in the Appendix. Since the specific pollution abatement regulations have varying impacts on refiners as a function of product output, capacity or raw material source, the specific 1973 capabilities will be defined in each subsection of the report. However, in general, the following industry sectors have been selected for analysis:

<u>Category</u>	<u>No. of Refiners</u>	<u>Crude Processing Capacity (B/D)</u>
Non-Gasoline Refiners (Primary Products Are Jet Fuel, Asphalt and Lubes)	68	700,000
Gasoline Refiners Under 20,000 B/D	42	396,000
Gasoline Refiners from 20,000 to 70,000 B/D Excluding California	64	2,657,000
Gasoline Refiners Between 70,000 and 150,000 B/D Excluding Calif.	34	3,496,000
Gasoline Refiners Over 150,000 B/D Excluding California	25	6,926,000
California Gasoline Refiners Over 20,000 B/D	18	1,690,000

E. Demand Forecast

After extensive review of five major energy studies completed in the past four years (1,2,3,4,5), we have concluded that the 1974 National Petroleum Council (NPC) study entitled "Emergency Preparedness: Interruption of Petroleum Imports into the United States" is the most valid for use at this point in time. A major strength of the NPC study is its analysis of the embargo experience and the presentation of a long-range demand forecast predicated on post-embargo government policies and industry pricing experience. A domestic petroleum demand forecast which has been developed based upon this study is presented in Table A-2 of the Appendix. Forecast 1985 domestic petroleum demand is set at 21.8 million barrels per day, reflecting a growth rate of 2.4% annually for the period 1974-1985. While this does not require federally imposed conservation programs or demand management, the outlook does assume that no new power plants are constructed which consume either petroleum or natural gas in the future. Thus, new petroleum demand is primarily oriented toward gasoline and distillate products. When consideration is given to product imports and products supplied by natural gas plants, the projected crude run in domestic refineries in 1985 is estimated at 17.2 million barrels per day, as outlined on Table A-3 in the Appendix.

F. Requirements for Future Refining Capacity

The announced and reasonably secure refinery capacity projects scheduled for completion by 1979 are presented in Appendix Table A-4. The major expansion projects scheduled for completion through 1976 are all well under way and not likely to be deferred or cancelled. The few large 1977 and 1978 projects could still be deferred, but would not significantly affect total refining capacity available to the industry in 1985. An analysis of scheduled capacity additions shows the following pattern:

	% of 1975-1978 Capacity Additions
Grassroots Refineries	17.0
Reactivation of Idle Plants	0.2
Major Expansions (Over 50% Increase)	39.3
Minor Expansions	43.5

We anticipate that this trend toward expansion at existing sites will continue due to industry economic considerations, as well as the environmental restrictions and general community resistance toward new refining centers.

A comparison of refinery capacity requirements with projected industry capacity yields the following estimate of new capacity additions by 1985:

	Million Barrels Per Calendar Day		
	Refinery Capacity Requirements	Refining Industry Capacity, January 1	Required Capacity Additions
1974	13.6	14.25	-
1978	16.4	17.1	-
1980	17.2	17.8*	-
1985	19.1	17.8*	1.3

*FEA Capacity Forecast as of 1/1/79

If the pattern of refinery capacity additions evidenced in the 1975-78 time period continues, only one or two new grassroots refineries should be expected in the 1980-1985 period with the balance of all new refining capacity being added to existing plants.

Assuming that product imports remain unchanged and new utility plants are not based on petroleum residual fuel, the following product slate will be required from incremental new domestic refining capacity:

	Demand Growth 1974-85, Mb/d	% of Total
Gasoline	1,868	36.9
Jet Fuels	739	14.6
Distillate Fuels	734	14.5
Residual Fuel	428	8.4
Petrochemical		
Feedstocks	551	10.9
Other Products	744	14.7
Total	5,064	

This implies that new refining capacity will include less extensive naphtha processing units compared to today's 50% gasoline yield domestic refinery. However, the major growth in petrochemical feedstock and distillate yields suggests that facilities will be required to upgrade residual stocks to distillate products.

It may be of interest to note the effect of not restraining the construction of petroleum-based utility plants. An earlier NPC study conducted prior to the 1973 embargo forecast residual fuel demand for 1985 at 4.2 million barrels daily. If such a demand materialized and were supplied by domestic refining capacity, 1985 refining capacity requirements would be increased by one million barrels daily and residual fuel yield would increase to 23.5% of total growth in demand.

This would further reduce the severity of future refinery operations. Though this may provide an important test case for parametric studies, one should also consider the opposite extreme. Two of the major projects already under construction (Exxon - Baytown and ECOL) are directed primarily toward the residual fuel market. Assuming a 50% residual fuel yield from these ventures, over half of the new domestic residual fuel refining capacity requirements forecast by NPC may already be committed. Thus, residual fuel yields from the remaining new refining ventures would average only 4% of refinery input - only half the level produced by the existing domestic refineries.

REFERENCES - SECTION II

1. U.S. Energy Outlook - An Initial Appraisal 1971-1985, National Petroleum Council, July 1971.
2. U.S. Energy Outlook - A Report of the National Petroleum Council, National Petroleum Council, December 1972.
3. U.S. Energy Prospects - An Engineering Viewpoint, National Academy of Engineering, May 1974.
4. Project Independence Report, Federal Energy Agency, November 1974.
5. Emergency Preparedness: Interruption of Petroleum Imports into the United States, National Petroleum Council, September 1974.

III. COST IMPACT OF WASTEWATER REGULATIONS

A. Background and Scope

The Federal Water Pollution Control Act Amendments of 1972 (Public Law 92-500) provided the basis for, and required that, EPA promulgate guidelines for the discharge of "pollutants" by industry. Accordingly, EPA has designated the petroleum refining industry as one of several "point source" categories to be regulated, and has promulgated⁽³⁾ existing-source effluent guidelines based on Best Practicable Control Technology Currently Available (BPCTCA) to be implemented by July 1, 1977, and based on Best Available Technology Economically Achievable (BATEA) to be implemented by July 1, 1983. New-source guidelines for Best Available Demonstrated Technology (BADT) have also been established. This report documents updated estimates of refining industry costs that can logically be expected to result from these established regulations. Using published data and information available as of January, 1975.

We have not considered the cost impact of potential regulations that may be promulgated by EPA after January, 1975. Estimated costs for those regulations, such as pre-treatment standards, would therefore have to be added to estimates developed herein. More specifically, the scope of this study is limited to estimation of the cost influence of BPCTCA, BATEA and BADT effluent guidelines together with assumed levels of refinery wastewater flow rates. Excluded are potential cost impacts of

- Pre-treatment standards for existing sources discharging to publicly-owned facilities (pre-treatment standards for new sources are implicitly assumed equivalent to BADT guidelines).
- Possible future limitations on discharging heavy metals, such as cadmium.
- Elimination of Discharge of Pollutants (DDP) guidelines, to be effective by July 1, 1983. These are yet to be developed since a definition of DDOP will probably not be available until October, 1975.
- Revised guidelines for each refinery, such as those resulting if EPA promulgates the more specific size and process factors proposed in the October 17, 1974, Federal Register. However, we would expect these to have little effect on total industry costs.

- Local, state and federal water quality statutes. Determining their effects on individual refineries and the industry would require more than the resources committed to this study.

It is worthwhile to note that current petroleum refining industry effluent guidelines and many of their implications are now in litigation. One of the major issues seems to be whether or not certain technology is in fact "currently available" (BPCTCA), "economically achievable" (BATEA) or "demonstrated" (BADT) in treating petroleum refinery wastewater. Also at issue is the correct interpretation of the word "guidelines". In our opinion, application of the specific combination of treating technology used in this and prior studies may or may not result in guidelines compliance for any given refinery. However, we do believe the model sequence of in-plant practices and end-of-pipe treating adopted in referenced studies and this one should result in a reasonable estimate of expected industry-wide investments and operating costs.

Because of unique terminology, we have included definitions of symbols and abbreviations on page III-20.

B. Conclusions

Using the best available information on costs and refinery wastewater control and treating practices, we have estimated the impact of EPA's current effluent guidelines and their underlying assumptions. In particular, cost estimates are almost entirely a function of wastewater flow rates. Individual-refinery compliance with guidelines, stated as pounds of pollutants per 1,000 barrels of crude charge, will of course depend on a combination of flow rate and final effluent pollutant concentrations. We have thus included a brief discussion of the guidelines, and refinery characterization under them, even though their direct influence on estimated costs is minimal.

Our review of prior studies and independent analysis indicate that:

- Total industry investment required by the application of commonly assumed technology should approach \$1.9 billion in the 1974 through 1977 period, rising to a 10-year total of almost \$2.9 billion by 1983.
- In existing refineries affected by either effluent guidelines or water quality regulations, investments are projected at about \$2.2 billion through 1983. New capacity should account for another \$0.7 billion, proportioned as 19% for grass-roots plants and 81% for expansions.

- Small existing refineries, i.e., those under 10 MB/SD in capacity, will be required to spend less than 4% of the industry total during the 10-year period. However, their average investment of about \$310 per daily barrel of capacity is more than twice the large-refinery figure of about \$150.
- Alternatives for small refineries in seeking relief from this projected burden seem to be:
 - refinery-specific studies that might indicate relatively cheap ways of reducing pollutant loadings and/or flow rates.
 - unique financing for required investments.
 - EPA-granted relief from guidelines compliance if other alternatives fail.

Unfortunately, small refineries usually do not have the technical manpower required to provide them with cost-effective solutions.

- Annualized industry costs of about \$750 MM by 1977, and \$1.15 billion in 1983, are composed of about 60% fixed charges and 40% direct operating costs. Per barrel of refining capacity, small refineries' annual costs should be almost twice those for other refineries at about 20 cents versus 16 cents.
- Our estimates should be adjusted when potential regulations such as pre-treatment standards for existing sources and EDOP are promulgated. It is likely that their projected cost impacts can be added to those developed in this study.

C. Guidelines Basis

Actual effluent guidelines as published in the Federal Register⁽³⁾ have not explicitly been used as a basis for cost estimates since they are in regulatory terms of maximum one-day and thirty-day average allowances. Instead, annual average daily figures, detailed for all pollutants in Tables III-1 and III-2, were used as a more rational basis for characterizing the industry and estimating certain investments.

In developing guidelines for the industry, EPA has adopted a general classification of refineries similar to that of API. Designated subcategories are topping, cracking, petrochemical, lube and integrated, as defined in Table III-3. Additionally, EPA analysis led to categorization of refineries by size and configuration⁽⁴⁾.

and to development of sets of size and process configuration factors. These factors, listed in Table III-4, should be applied to the basic discharge limitations (shown in Table III-1) in calculating target annual average daily allowances for individual refineries.

D. Industry Characterization

Each operating refinery in the United States, as of January 1, 1974, is listed in Appendix Table A-1 together with published data on processes and capacities. This list includes not only those refineries in the lower-48 states, but also contains two refineries in Hawaii, four in Alaska, one in Guam, three in Puerto Rico and one in the Virgin Islands. These remote refineries have been included since they are within the jurisdiction of EPA in regulating and controlling pollution abatement practices.

In developing information needed to estimate the cost impact of wastewater guidelines, we have calculated allowable pollutant discharge levels of BOD₅ for aggregated refining subcategories in both 1977 and 1983 to be used in estimating sludge handling costs.

Further stratification of refineries is necessary to account for certain influences on industry-wide cost estimates. Accordingly,

- Zero dischargers and those refineries discharging to offsite treatment facilities were excluded.
- The cost influence of Amerada-Hess' refinery at St. Croix, V.I., was estimated separately since the plant accounts for almost 40% of topping-subcategory capacity.
- Small refineries, i.e., those with less than about 10 MB/D capacity, were segregated.

Table III-5, summarized below, shows the domestic refining population adjusted for the above influences and assumptions.

Refineries	Cap. ≤ 10 MB/SD		Cap. > 10 MB/SD		Total	
	No.	MB/SD	No.	MB/SD	No.	MB/SD
Total	70	340	180	14,900	250	15,240
Zero Discharge & Offsite Treatment	17	70	35	1,755	52	1,825
Effluent & Water- Quality Limited	53	270	145	13,145	198	13,415

Note: Excluding the Amerada-Hess refinery at St. Croix, V.I.

Estimated allowable discharge levels for BOD₅ were adjusted for the above considerations and are summarized below.

	BOD ₅ , M#/Day	
	1977	1983
All Refineries	72.0	15.30
Less -		
Non-dischargers	8.3	1.70
Dischargers ≤ 10MB/SD	0.7	0.12
Amerada-Hess(V.I.)	1.5	0.25
Subtotals	10.5	2.07
Dischargers > 10MB/SD	61.5	13.23

The resulting 1977 and 1983 figures for dischargers over 10 MB/SD capacity were used for estimating sludge handling costs in Section III-F-2.

E. Estimating Basis

1. Approach

We have relied heavily on relevant studies that used published data in combination with a specific cost-estimating procedure. Of the two published studies that deal comprehensively with expected costs, we have chosen Brown & Root's⁽²⁾ instead of the one by Roy F. Weston⁽¹⁾ because:

- The level of detail included in the Brown & Root study allows adjustment of their cost estimates for major differences in such key parameters as target flow rates for 1977 and 1983.
- A corollary to the Brown & Root study⁽⁸⁾ contains specific data from the 1972 RWL Survey on several small refineries. Combined with certain new independent estimates, these data supported a more detailed estimate of cost impacts on the small refinery group.
- The Weston study included neither an estimate of in-plant control and flow-reduction costs*, nor credit for then-existing, end-of-pipe treating facilities. The Brown & Root study attempted to account for both of these important cost influences.

*A more recent EPA study⁽¹²⁾ did include an aggregate estimate of such costs.

- The Brown & Root study, in addition to previously published investment and operating cost data, included new case-history data that either filled a void or expanded on available information.

Since our basic approach has been to update and modify the Brown & Root study, it should be assumed as the basis for discussion in following sections unless references indicate otherwise.

2. In-Plant Practices and Treatment Technology

The 1973 Brown & Root study was based on technology then assumed to be available for BPCTCA and BADT requirements, and on activated carbon adsorption as the add-on treatment process most likely to be proven in attempting to meet BATEA guidelines by 1983. Essentially no new alternatives to these assumptions have developed to the point of being proven in treating refinery wastewater. However, we note that current alternatives within a class of treating processes existed even then. For example, trickling filters, aerated lagoons, bio-oxidation (cooling) towers and oxidation ponds are alternatives to the selected activated sludge process. But, we believe the basic referenced approach of applying the same set of in-plant and end-of-pipe steps to each refinery, if required, remains valid as a computational procedure intended only to measure potential industry-wide costs.

Available in-plant pollution control practices, flow reduction techniques and end-of-pipe treating technology have been extensively discussed in the literature^(2,4,9). Therefore, excepting certain alternatives discussed in a following section on small refineries, our review of specific practices is limited to a listing below and a brief statement of key assumptions adapted from the Brown & Root study.

	<u>IN-PLANT CONTROL/FLOW REDUCTION</u>	<u>END-OF-PIPE TREATING</u>
LEVEL 1: (1977)	Conversion of Barometric to Surface Condensers	Equalization
	Sour-Water Stripping	Dissolved Air Flotation
	Storm Water Handling and Segregation	Activated Sludge
	Miscellaneous Flow Reductions	Final Filtration
	Collection of Multiple Effluents for Common Treatment	Indirect, Associated Steps
		Sludge-Handling Facilities
LEVEL 2: (1983)		Auxiliary Facilities
	Elimination of Once-Through Cooling Water (OTCW)	Final Filtration
	Water Reuse, Including Softening and Redistribution	Activated Carbon Adsorption
	Cooling Tower Blowdown Treatment for Reuse	Additional Sludge Handling
		Off-Specification Handling and Reuse Basin

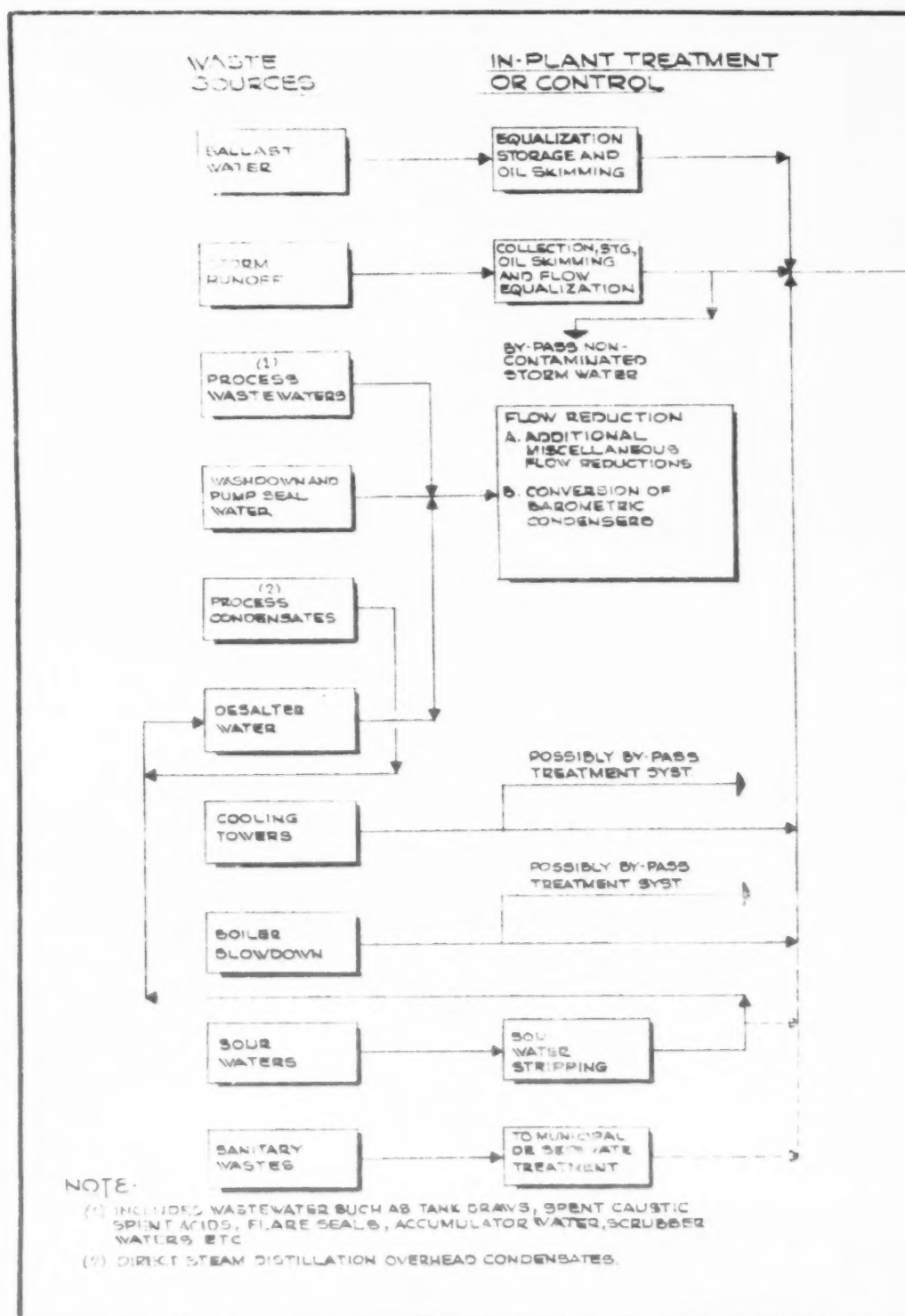
The figures on pages 8 and 9 illustrate resulting wastewater flow sequences for Level 1 and Level 2 treating in a hypothetical refinery. Complete details and extensive discussion of practices and underlying treatment technology assumptions are available in Reference 2.

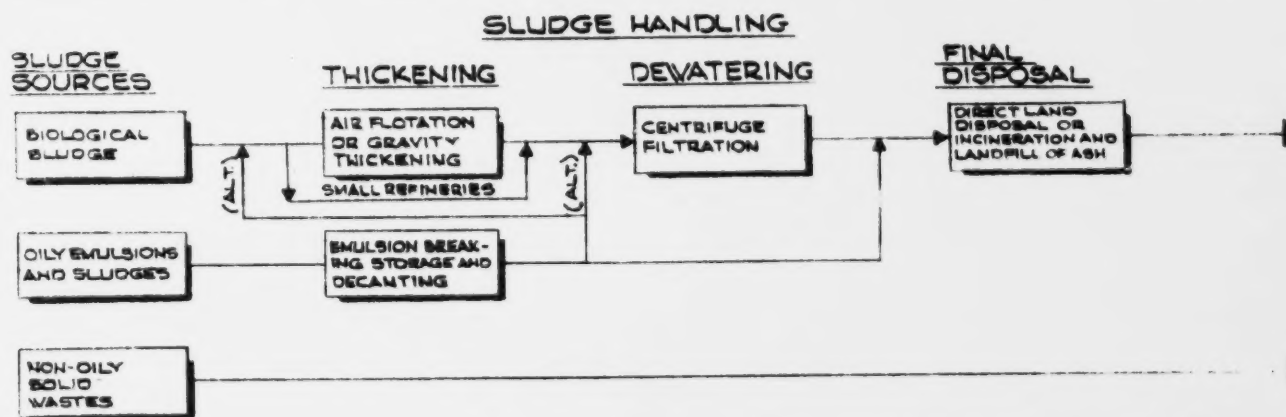
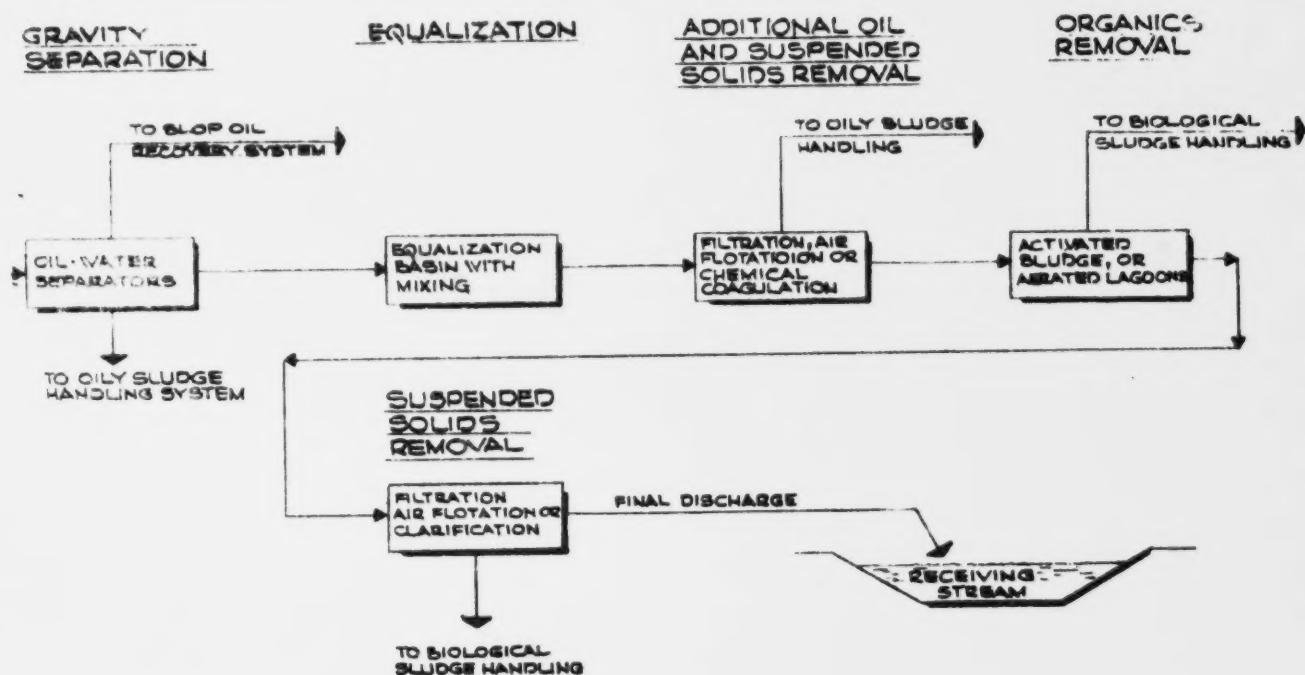
With the exception of when OTCW must be eliminated, BPCTCA and BATEA treating practices are assumed in this study to be equivalent to Level 1 and Level 2 as defined above.

3. Flow Levels

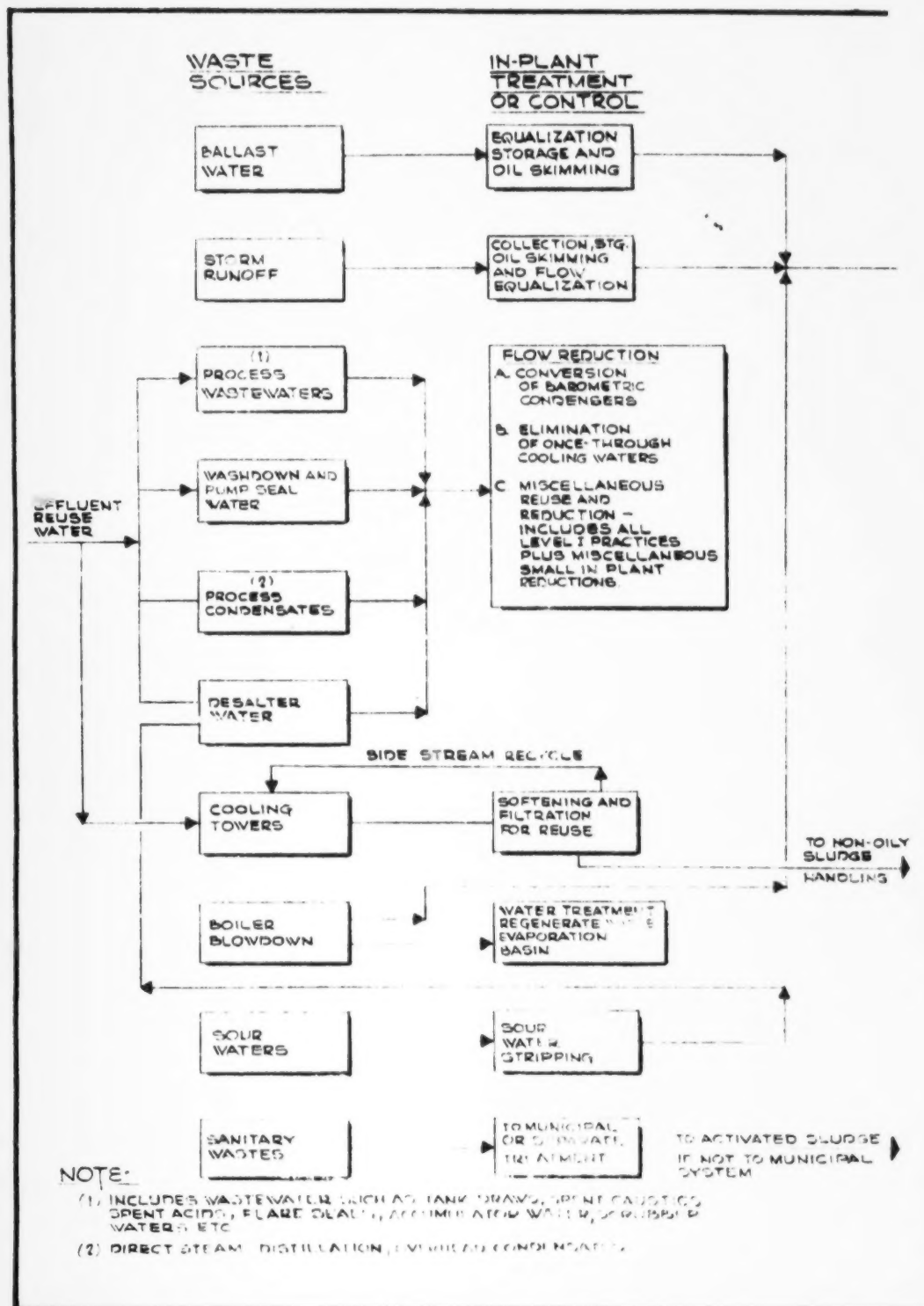
Wastewater flow levels assumed in the Brown & Root study are contrasted below with those used by EPA in developing the guidelines.

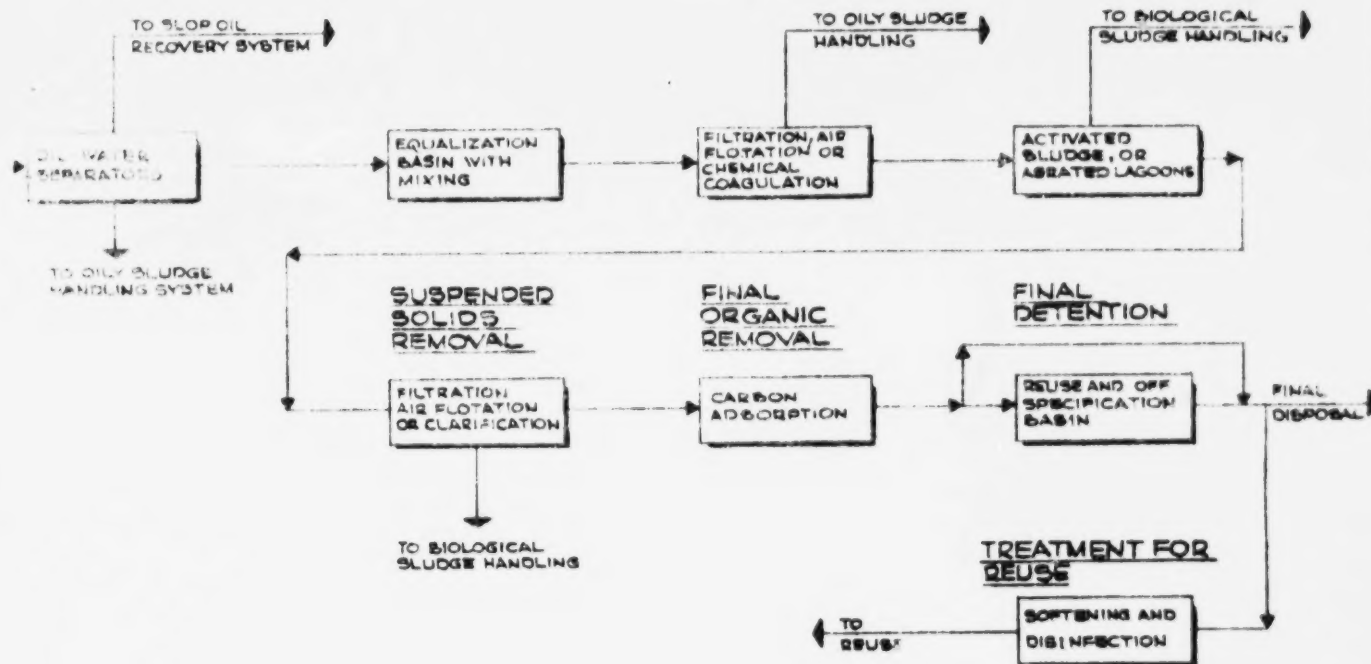
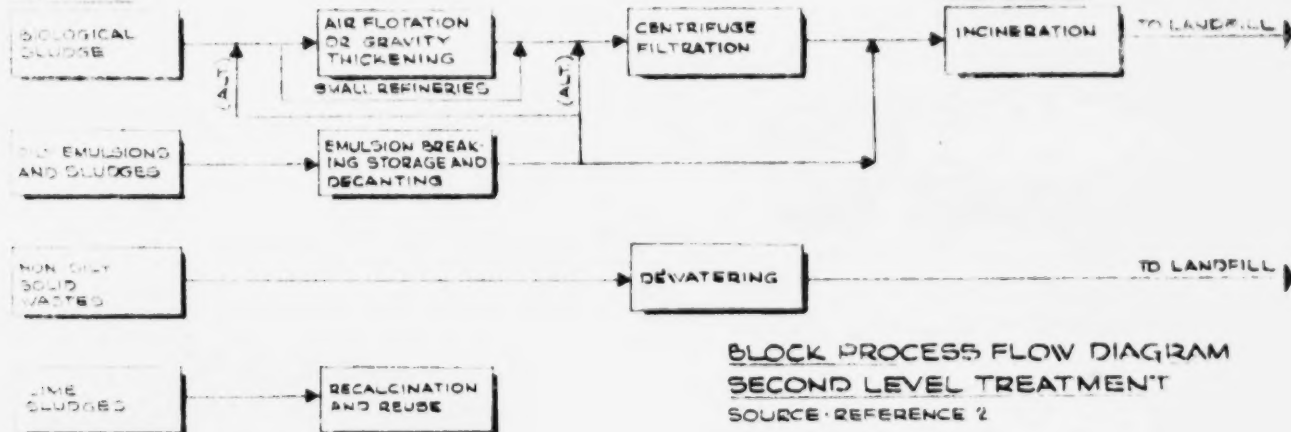
Class, or Subcategory	Gal./Bbl. of Crude			
	1977		1983	
	B & R Level 1	BPCTCA	B & R Level 2	BATEA
A	20	20	2.4	10.5
B	40	25	4.7	14
C	50	30	4.4	19
D	60	45	4.8	30.5
E	90	48	7.2	36.5





**BLOCK PROCESS FLOW DIAGRAM
FIRST LEVEL TREATMENT
SOURCE: REFERENCE 2**



GRAVITY SEPARATIONEQUALIZATIONADDITIONAL OIL AND SUSPENDED SOLIDS REMOVALORGANICS REMOVALSLUDGE HANDLINGSLUDGE SOURCESTHICKENINGDEWATERINGFINAL DISPOSAL

BLOCK PROCESS FLOW DIAGRAM
SECOND LEVEL TREATMENT
SOURCE: REFERENCE 2

Except for oily, biological and lime-sludge handling facilities, the size and required investment for almost all in-plant and end-of-pipe facilities are primarily dependent on hydraulic loadings. Refiners therefore have a basic tradeoff available to them since increased in-plant investments to reduce flows will allow lower investments in end-of-pipe treating facilities. Recognizing that the most cost-effective combination of flow rate and effluent concentrations will be determined by studying individual refinery situations, we have assumed that the above BPCTCA and BATEA flows for refining subcategories will be met by each corresponding refinery unless the available 1972 RWL Survey data indicated an existing lower level.

4. Investments and Operating Costs

Compared below are Brown & Root's bases for investments and operating costs with those used in this study.

<u>Assumption</u>	<u>Current Basis</u>	<u>Brown & Root Study</u>
Time Reference	1974 through 1983	1973 through 1985
Const. Costs	1974 dollars	1972 dollars
Location	B & R Area 3 (roughly equivalent to U. S. Gulf Coast)	Five cost areas
Land Required	Assumed available at no cost	Assumed available at no cost
Existing Facilities	Credited, based on 1972 RWL Survey data and estimated 1973 ⁽¹⁾ investments	Credited, based on 1972 RWL Survey data
Operating Costs	Related to investment	Related to investment
Fixed Annual Costs, % of Investments	Capital charge equivalent to 12% DCF, 21.82% Taxes & Ins., 4.0%	Amortization, 6.67% Interest cost, 10.0% Taxes & Ins., 1.0%

F. Investment Estimates

1. Cost Estimating Procedure

To determine required investments, Brown & Root divided the industry into four basic categories:

- Existing refineries over 10 MB/SD capacity.
- Existing refineries under 10 MB/SD capacity.
- New grass-roots capacity to 1985.
- Expansions to 1985.

Then, from the sample responding to the 1972 RWL Survey, they selected 121 refineries, larger than 10 MB/SD capacity, on which sufficient and consistent data were available. Investments, if required, were estimated for each refinery, totaled for the 121 refineries, and extrapolated to all 156 existing large refineries. Total investment for refineries under 10 MB/SD capacity was scaled, using average capacities, to complete the estimate for existing plants. Investments for then-projected new refineries and expansions were developed and added to existing-refinery requirements to obtain an industry total.

By adjusting the large-refinery estimates to the bases for this study, we implicitly adopt certain assumptions about contingencies, indirect costs and excess capacity that are more generous than those we would have assumed. However, we believe the degree of detail and integrity of approach utilized in the Brown & Root study justify it as the primary basis for a current estimate.

2. Refineries Over 10 MB/SD Capacity

Beginning with Brown & Root's refinery-by-refinery investment estimates for 121 large refineries, we first adjusted them to an Area 3 basis^(2,10). Also, estimates for eliminating OTCW were shifted from Level 2 to Level 1 since we believe this conversion will be required to meet BPCTCA effluent guidelines.

Next, estimates were adjusted to conform with the bases for current effluent guidelines. The procedure used was:

- Investments for converting OTCW, sour-water stripping, storm-water handling, converting barometric condensers, collecting multiple effluents and auxiliary facilities were left unchanged since they are primarily a function of individual refinery characteristics
- Differences between BPCTCA and Brown & Root's Level 1 target flow rates for refining classes B, C, D and E dictated recomputation for each refinery of investments for miscellaneous in-plant flow reductions. Example calculations for a sample of Class B refineries are shown in Table III-6.
- All other investments, except sludge handling facilities, were adjusted to current flow basis assumptions using appropriate combinations of original and recalculated average refinery-class flows. These are tabulated and compared below.

Refinery Class	Average Flow, Gal./Bbl. of Crude			
	B&R	B&R	BPCTCA	BATEA
	Level 1	Level 2		
A	14.5	2.0	14.5	9.1
B	29.5	4.63	20.7	13.1
C	38.5	4.40	25.7	17.7
D	42.0	4.80	36.9	28.6
E	63.7	7.20	42.5	34.7

- Investments for sludge handling facilities were assumed to be a function of BOD₅ removed. Accordingly, we developed the following aggregate industry estimates:

BOD ₅ Discharge Level	#/MBbls.
1972 Existing	31.75
B & R Level 1	13.23
BPCTCA	4.73
B & R Level 2	3.08
BATEA	1.02

Note: All BOD₅ discharge levels exclude OTCW effects.

Using logic similar to that for making flow-dependent adjustments above, we recalculated sludge handling investments.

Resulting modified investments for the 121-refinery group based on BPCTCA and BATEA target flow rates and BOD₅ discharge levels are contained in Table III-7 and summarized below.

Refinery Class	Investment, MM\$		
	BPCTCA	BATEA	Totals
A	19	8	27
B	385	112	497
C	258	85	343
D	81	37	118
E	256	78	334
Totals -	999	320	1,319

Basis: Area 3, 1972 \$.

Comparisons between refinery classes should be avoided since adjusted investments for sludge handling are based on average BOD₅ discharge levels for the entire group of 121 refineries.

3. Refineries Under 10 MB/SD Capacity

We have devoted significant attention to potential problems faced by the group of 53 small refineries (excluding 17 zero dischargers and offsite-treatment refineries) in attempting to meet 1977 and 1983 effluent guidelines. In particular, we have reviewed current treating facilities and plans for guidelines compliance with the management of 9 plants. Unfortunately, this has not particularly sharpened cost estimates since almost none have specific plans. Our review did, however, provide insight to support the following opinions:

- With few exceptions, in-house technical personnel are not available to evaluate treating alternatives and identify opportunities to reduce pollutant loads through good water-use practices and flow-reduction projects.
- While uncommon, at least one small refinery has already installed cooling towers to eliminate OTCW, has instituted other flow-reduction practices, and projects a 75 to 80% reduction.

- Installation of several small API separators ahead of an existing single unit may cost less and be a more effective use of scarce land than flow equalization facilities to protect against process unit spills.
- The two most common methods of effluent treating seem to be direct discharge from API separators, and 12 to 24-hour holding ponds sequenced between API separators and discharge points.
- Several small topping-subcategory refineries, including some in the 10 to 20 MB/SD range, are already zero-dischargers and face no problems unless they plan significant capacity expansions. We are aware of at least one planned refinery being designed for zero discharge.

Although the same treating processes have been assumed as model technology for small refineries, it is entirely possible that novel technology could find application in the refining industry - particularly for those plants with low potential discharge rates. Brine concentrators using a vapor-compression cycle are commercial in the electric utility industry, and this technology is being tested on refinery wastewater. If such commercial technology were proven for treating API separator effluent, a 3,600 B/D refinery at the BPCTCA-level of 20 gal/Bbl. could approach or even achieve zero discharge with a brine concentrator capacity of about 50 gpm. This treating scheme could supplant the need for bio-treatment, air flotation, filtration and activated carbon adsorption--while meeting 1983 guidelines now. Required investment for this hypothetical example would be in the range of \$350-550M (Area 3, 1972 \$), or about \$125 per B/D of crude capacity. Annual energy costs should be less than 3% of investment since existing installations use only about one-tenth the energy required for conventional multiple-effect evaporators.

These observations serve as a useful background in evaluating the potential impact of EPA's effluent guidelines. In particular, our discussions indicated that small refineries will continue to be more cost-conscious than large ones in such areas as indirect costs, control schemes and excess capacity. Our estimation of investments accordingly reflects this traditional, small-refiner posture. We stress that, even though investments were individually calculated for a sample of small refineries, our purpose was to develop an aggregate estimate. A specific study would be required to develop definitive estimates for any one refinery.

Results for a sample of six Class A and five Class B small refineries are listed in Table III-8. Average results of these sample estimates were extrapolated to all small refineries, as indicated in Table III-9 and summarized below.

EPA Subcat.	No.	Capacity, MB/SD		Total Investment		
		Total	Avg.	MM\$	\$/B/D	MM\$/Ref.
A	42	206	4.9	41	199	1.0
B	11	64	5.8	19	300	1.8
Totals	53	270	5.1	60	223	1.1

Basis: Area 3, 1972 \$.

In developing these estimates, we modified the procedure used by Brown & Root in calculating investments for larger refineries. Specifically, we have:

- Not included any provision in sour-water stripping investments for high-nitrogen crude effects, or for extra steam.
- Scaled storm-water and sludge handling investments based on averages for several 10 to 20 MB/SD plants⁽²⁾.
- Included no investment for auxiliary facilities.
- Not sized treating facilities for 25% excess hydraulic capacity.

We recognize the potential inaccuracy of extrapolating investment curves based on projects for much larger refineries. However, short of resorting to specific studies of individual small refineries, we believe the data and assumptions used are the best currently available information.

4. New Capacity

Projected new refining capacity from 1974 through 1983 has been divided into grass-roots and expansion capacity. Beginning with 1974 additions, this projection is tabulated below as the basis for estimating wastewater-related investments.

Year	Capacity Added, MB/SD		
	Grass-Roots	Expansions	Total
1974	-	684	684
1975	50	523	573
1976	222	1,200	1,422
1977	111	405	516
1978	167	555	722
1979	148	64	212
1980	-	212	212
1981	148	64	212
1982	-	212	212
1983	-	212	212
Totals	846	4,131	4,977

Estimates for new grass-roots capacity were based on the following assumptions:

- Average capacity for the seven projected plants would be about 120 MB/SD.
- In-plant expenditures would be required to forego the use of OTCW, reduce estimated pre-guideline flow from 33 gal/Bbl. to the BADT level of 14, handle storm water, collect multiple effluents and provide for sour-water stripping.
- Auxiliary facilities, BPCTCA treating processes and activated carbon adsorption would be necessary to meet BADT guidelines and, eventually, 1983 BATEA guidelines.

Basic investment curves from Reference 2 were used with the above assumptions resulting in an estimated investment of about \$13.2 MM for a hypothetical 120 MB/SD refinery.

Investments required for capacity expansions were calculated to be \$51.7/B/D for BPCTCA and \$44.1/B/D for BATEA. These are based on reported⁽²⁾ figures, adjusted to conform to our assumptions.

Applying these estimates to the previously-listed time series of capacity expansions results in the estimates shown in Table III-10, also summarized below.

Period	Investment MM\$		
	Grass-Roots	Expansions	Total
1974-77	42	145	187
1978-83	50	251	301
Totals	92	396	488

Basis: Area 3, 1972 \$.

5. Investment Summary

An accumulation of investments for existing large and small refineries together with those for new capacity, adjusted to account for inflation between 1972 and 1974, provides the following industry summary:

	MM\$		\$/B/D	
	1974-77	1978-83	1974-83	
Existing Capacity				
Over 10 MB/SD	1,550	529	2,079	151
Under 10 MB/SD	60	24	84	312
Subtotal	1,610	553	2,163	154
New Capacity				
Grass-Roots	59	71	130	154
Expansions	189	366	555	135
Subtotal	248	437	685	138
Total Industry	1,858	990	2,848	150

Basis: Area 3, 1974 \$.

This summary excludes an estimated refining industry capital expenditure in 1973 of about \$77 MM (Ref. 11, adjusted). The remaining \$1,610 MM needed for BPCTCA requirements in existing capacity must be spent prior to July 1, 1977 - a rate of about \$460 MM per year for 3 1/2 years. The estimate of \$553 MM for BATEA-imposed capital requirements in existing refineries indicates average annual capital expenditures of about \$90 MM during the 1978-83 period. These drastically different rates of expenditure nevertheless seem indicated by underlying study assumptions.

G. Annualized Costs

Annual industry costs in 1977 and 1983 were developed by adding a fixed charge for capital recovery, insurance and taxes to estimated direct operating costs. Based on assumptions discussed earlier, 25.82% of investment was assumed to represent fixed charges. Direct operating costs were calculated by:

- estimating expenses, shown in Table III-11, for the 121 large refineries used in Reference 2.
- extrapolating this estimate to all affluent and water-quality limited refineries with over 10 MB/SD capacity.
- adding estimates for affected small refineries and new capacity.

Results, summarized below, indicate annualized costs of about \$750 MM in 1977, rising to a total of almost \$1.2 billion by 1983.

	MM\$/Year					
	1977			1983		
	Direct Oper.	Fixed	Total	Direct Oper.	Fixed	Total
Existing Capacity:						
Over 10 MB/SD	209	388	597	285	520	805
Under 10 MB/SD	5	15	20	8	21	29
Subtotal	214	403	617	293	541	834
New Capacity:						
Grass-Roots	7	15	22	15	33	48
Expansions	58	47	105	126	139	265
Subtotal	65	62	127	141	172	313
Total All Refineries	279	465	744	434	713	1,147

Basis: Area 3, 1974 \$.

Results in both years will be highly sensitive to fixed charges since these represent over 60% of the total for all refineries and more than 70% for small refineries. When operating at capacity, average product price increases required to fully recover annualized costs would have to be:

Refineries	\$/Barrel	c/Gallon
Existing Over 10 MB/SD	0.16	0.4
Existing Under 10 MB/SD	0.30	0.7
New Grass-Roots	0.16	0.4
Expansions	0.18	0.4

The average smaller refinery thus seems to face a relative cost disadvantage of about 0.3 cent per gallon on its refined products.

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SYMBOLS & ABBREVIATIONS - SECTION III

API - American Petroleum Institute
B/D - Barrels per day
B&R - Brown & Root, Inc.
B/SD - Barrels per stream day
BADT - Best Available Demonstrated Technology
BATEA - Best Available Technology Economically Achievable
Bbl. - Barrel(s)
BOD₅ - Five-day biochemical oxygen demand
BPCTCA - Best Practicable Control Technology Currently Available
COD - Chemical oxygen demand
Cr - Chromium
DCF - Discounted cash flow
EDOP - Elimination of Discharge of Pollutants
EPA - Environmental Protection Agency
Gal. - Gallon(s)
M - Thousands
mg - Milligram(s)
MM - Millions
N - Nitrogen
NH₃ - Ammonia
NPDES - National Pollutant Discharge Elimination System
OTCW - Once-through cooling water
ROR - Rate of return
RWL - Raw waste load
TOC - Total organic carbon
TSS - Total suspended solids

TABLE III-1

WATER⁽¹⁾ EFFLUENT LIMITATIONSPETROLEUM REFINING (POINT SOURCE) CATEGORY(Annual Average Daily Pounds of Pollutants per MBbls. Feedstock⁽²⁾)

	<u>BPCTCA</u> <u>(1977)</u>	<u>BATEA</u> <u>(1983)</u>	<u>BADT</u> <u>(New Source)</u>
<u>A-Topping Subcategory</u>			
BOD5	2.5	0.44	1.3
COD(3)	13.3	1.75	7.0
TOC	5.5	1.3	2.9
TSS	1.7	0.44	0.88
Oil & Grease	0.83	0.088	0.44
Phenolic Cpds.	0.017	0.0018	0.0088
NH ₃ as N	0.3	0.12	0.3
Sulfide	0.017	0.0087	0.0088
Total Cr	0.042	0.022	0.022
Hexavalent Cr	0.0008	0.00044	0.00044
<u>B-Cracking Subcategory</u>			
BOD5	3.1	0.58	1.8
COD(3)	24.0	3.4	13.4
TOC	6.8	1.75	4.0
TSS	2.1	0.58	1.2
Oil & Grease	1.0	0.12	0.58
Phenolic Cpds.	0.021	0.0023	0.012
NH ₃ as N	2.0	0.8	2.0
Sulfide	0.021	0.012	0.012
Total Cr	0.052	0.029	0.029
Hexavalent Cr	0.001	0.00058	0.00058
<u>C-Petrochemical Subcategory</u>			
BOD5	3.8	0.79	2.4
COD(3)	24.0	3.8	15.2
TOC	8.3	2.4	5.3
TSS	2.5	0.79	1.6
Oil & Grease	1.3	0.16	0.79
Phenolic Cpds.	0.025	0.0032	0.016
NH ₃ as N	2.5	1.0	2.5
Sulfide	0.025	0.016	0.016
Total Cr	0.063	0.04	0.04
Hexavalent Cr	0.0013	0.00079	0.00079

TABLE III-1

(continued)

	<u>BPCTCA</u> <u>(1977)</u>	<u>BATEA</u> <u>(1983)</u>	<u>BADT</u> <u>(New Source)</u>
<u>D-Lube Subcategory</u>			
BOD5	5.6	1.3	3.8
COD(3)	41.0	6.9	28.0
TOC	12.4	3.8	8.4
TSS	3.8	1.3	2.5
Oil & Grease	1.9	0.25	1.25
Phenolic Cpds.	0.038	0.0051	0.025
NH ₃ as N	2.5	1.0	2.5
Sulfide	0.038	0.025	0.025
Total Cr	0.094	0.063	0.062
Hexavalent Cr	0.0019	0.0013	0.0013
<u>E-Integrated Subcategory</u>			
BOD5	6.0	1.5	4.6
COD(3)	44.0	8.4	33.5
TOC	13.2	4.6	10.1
TSS	4.0	1.5	3.0
Oil & Grease	2.0	0.3	1.5
Phenolic Cpds.	0.04	0.0061	0.03
NH ₃ as N	2.5	1.0	2.5
Sulfide	0.04	0.03	0.03
Total Cr	0.10	0.076	0.076
Hexavalent Cr	0.002	0.0015	0.0015
<u>All Subcategories</u>			
pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0

Source: Reference 4

- (1) Once-through cooling water is excluded. It may be segregated and discharged with a TOC limit of 5 mg per liter of discharge (flow).
- (2) Combined crude oil and natural gas liquids charged to the "topping" units in a given refinery (for all subcategories).
- (3) If effluent chloride-ion concentration exceeds 1,000 mg per liter (1,000 ppm), TOC may be used in lieu of COD. Without adequate data, use TOC/BOD5 = 2.2/1.0.

TABLE III-2
LIMITATIONS⁽¹⁾ ON ADDITIONAL
DISCHARGE ALLOWED

(Annual Average Daily Pounds of Pollutants per MGals. of Flow)

	<u>BPCTCA</u> <u>(1977)</u>	<u>BATEA</u> <u>(1983)</u>	<u>BADT</u> <u>(New Source)</u>
<u>Runoff⁽²⁾</u>			
BOD5	0.125	0.042	0.125
COD ⁽³⁾	1.0	0.12	1.0
TOC	0.275	0.13	0.275
TSS	0.083	0.042	0.083
Oil & Grease	0.042	0.009	0.042
<u>Ballast⁽⁴⁾</u>			
BOD5	0.125	0.042	0.125
COD ⁽³⁾	1.25	0.16	1.25
TOC	0.275	0.13	0.275
TSS	0.083	0.042	0.083
Oil & Grease	0.042	0.009	0.042

Source: Reference 4

NOTE: pH, for runoff and ballast (each), is limited to a range of 6.0 to 9.0 for BPCTCA, BATEA and BADT.

- (1) Apply to all refining subcategories.
- (2) Process area runoff treated in the main treatment system. All other runoff, segregated for discharge, must meet maximum limitations of 35 mg per liter for TOC and 15 mg per liter for oil & grease.
- (3) If effluent chloride-ion concentration exceeds 1,000 mg per liter (1,000 ppm), TOC may be used in lieu of COD. Without adequate data, use TOC/BOD5 = 2.2/1.0.
- (4) Those waters, from a ship, actually treated at a refinery.

TABLE III-3
SUBCATEGORIZATION OF THE PETROLEUM REFINING INDUSTRY

<u>Subcategory</u>	<u>Basic Refinery Operations Included</u>
Topping	Topping and catalytic reforming, whether or not the facility includes any other processes. This subcategory is not applicable to facilities which include thermal processes (coking, visbreaking, etc.) or catalytic cracking.
Cracking	Topping and cracking, whether or not the facility includes any processes in addition to topping and cracking, unless specified in one of the subcategories listed below.
Petrochemical	Topping, cracking and petrochemical operations, whether or not the facility includes any process in addition to topping, cracking and petrochemical operations,* except lube oil manufacturing operations.
Lube	Topping, cracking and lube oil manufacturing processes, whether or not the facility includes any process in addition to topping, cracking and lube oil manufacturing processes, except petrochemical operations.*
Integrated	Topping, cracking, lube oil manufacturing processes, and petrochemical operations, whether or not the facility includes any processes in addition to topping, cracking, lube oil manufacturing processes and petrochemical operations.*

Source: Reference 4.

- * The term "petrochemical operations" shall mean the production of second generation petrochemicals (i.e., alcohols, ketones, cumene, styrene, etc.) or first generation petrochemicals and isomerization products (i.e., BTX, olefins, cyclohexane, etc.) when 15% or more of refinery production is as first generation petrochemicals and isomerization products.

TABLE III-4
SIZE AND PROCESS FACTORS

	Size Factor			Process Factor		
	Range No. (2)	Feedstock ⁽¹⁾ MB/SD	Factor	Range No. (2)	Configuration	Factor
<u>A-Topping Subcategory</u>	1	0 to 49.9	1.02	1	1.0 to 3.99	0.60
	2	50 to 99.9	1.21	2	4.0 to 6.99	1.00
	3	100 to 149.9	1.44	3	7.0 to 9.99	1.66
	4	150 +	1.57	4	10.0 to 12.99	2.77
				5	13.0 +	4.09
<u>B-Cracking Subcategory</u>	1	0 to 34.9	0.89	1	1.5 to 3.49	0.58
	2	35 to 74.9	1.00	2	3.5 to 5.49	0.81
	3	75 to 109.9	1.14	3	5.5 to 7.49	1.13
	4	110 to 149.9	1.31	4	7.5 to 9.49	1.60
	5	150 +	1.41	5	9.5 +	1.87
<u>C-Petrochemical Subcategory</u>	1	0 to 49.9	0.73	1	3.25 to 4.74	0.67
	2	50 to 99.9	0.87	2	4.75 to 6.74	0.91
	3	100 to 149.9	1.04	3	6.75 to 8.74	1.27
	4	150 +	1.13	4	8.75 +	1.64
<u>D-Lube Subcategory</u>	1	30 to 69.9	0.71	1	6.0 to 7.99	0.88
	2	70 to 109.9	0.81	2	8.0 to 9.99	1.23
	3	110 to 149.9	0.93	3	10.0 to 11.99	1.74
	4	150 to 199.9	1.09	4	12.0 +	2.44
	5	200 +	1.19			
<u>E-Integrated Subcategory</u>	1	70 to 144.9	0.69	1	6.0 to 7.49	0.78
	2	145 to 219.9	0.89	2	7.5 to 8.99	1.00
	3	220 +	1.02	3	9.0 +	1.30

Source: Reference 4

- (1) Combined crude oil and natural gas liquids charged to the "topping" units in a given refinery.
- (2) Range numbers are used to define a shorthand notation for refinery type. For example, a type B24 refinery would be one in the cracking subcategory (B) with a feedstock capacity in the range of 35 to 74.9 MB/SD(2) and a process configuration in the range of 7.5 to 9.49(4).

Note: The formula for calculating a refinery's configuration is given on pages 148 - 150 in Reference 4.

TABLE III-5
APPROXIMATE CAPACITIES OF EFFLUENT AND
WATER-QUALITY LIMITED REFINERIES

Subcategory	Refineries < 10 MB/SD			Refineries ~ 10 MB/SD			All Refineries		
	No.	Capacity, MB/SD Total	Avg.	No.	Capacity, MB/SD Total	Avg.	No.	Capacity, MB/SD Total	Avg.
• All Refineries									
Topping	58	272.0	4.7	30	666.1	21.5	88	938.1	10.7
Cracking	11	66.1	6.0	101	6,129.7	60.7	112	6,195.8	55.3
Petrochemical	0	-	-	23	3,045.1	132.4	23	3,045.1	132.4
Lube	1	3.7	3.7	17	2,932.7	172.5	18	2,936.4	163.1
Integrated	0	-	-	9	2,127.1	236.3	9	2,127.1	236.3
Totals	70	341.8	4.9	180	14,900.7	82.8	250	15,242.5	61.0
• Zero Discharge & Offsite Treatment Refineries									
Topping	16	66.2	4.1	9	192.8	21.4	25	259.0	10.4
Cracking	1	5.5	5.5	20	839.3	42.0	21	844.8	40.2
Petrochemical	0	-	-	3	341.4	113.8	3	341.4	113.8
Lube	0	-	-	2	146.3	73.2	2	146.3	73.2
Integrated	0	-	-	1	233.5	233.5	1	233.5	233.5
Totals	17	71.7	4.2	35	1,753.3	50.1	52	1,825.0	35.1
• Effluent & Water Quality Limited Refineries									
Topping	42	205.8	4.9	21	473.3	22.5	63	679.1	10.8
Cracking	10	60.6	6.1	81	5,290.4	65.3	91	5,351.0	58.8
Petrochemical	0	-	-	20	2,703.7	135.2	20	2,703.7	135.2
Lube	1	3.7	3.7	15	2,786.4	185.8	16	2,790.1	174.4
Integrated	0	-	-	8	1,893.6	236.7	8	1,893.6	236.7
Totals	53	270.1	5.1	145	13,147.4	90.7	198	13,417.5	67.8

Basis: As of January 1, 1974.

Note: The Amerada-Hess refinery at St. Croix, V.I., has been excluded from the Topping subcategory and all affected totals.

TABLE III-6
RECALCULATED INVESTMENTS
FOR MISCELLANEOUS FLOW REDUCTIONS-
SAMPLE OF CLASS B REFINERIES

1972 Ref. (1) Cap., MB/SD	RWL Survey Flow, g/B	OTCW	Bar. (2) Cond.	Gal./Bbl.		New Percent Reduction	Investment, MM\$	
				Assumed Flow After Elim. OTCW & B.C.	Flow After Misc. Flow Reductions		Original B & R	New Area 3
105.0	1,144.19	Yes	-	40.0	25.0	37.5	-	0.18
12.7	11.05	-	Yes	4.75	4.75	-	-	-
51.0	13.53	-	-	13.53	13.53	-	-	-
165.0	111.56	Yes	-	83.0	25.0	69.9	2.50	7.90
125.0	174.24	Yes	-	91.0	25.0	72.5	3.45	9.12
11.5	14.07	-	-	14.07	14.07	-	-	-
11.2	199.66	Yes	-	40.0	25.0	37.5	-	0.05
110.0	85.82	-	-	85.82	25.0	70.9	1.90	6.97
76.0	34.56	-	-	34.56	25.0	27.7	-	0.05

Basis: References 2 and 8. Original target flow was 40 gal./Bbl; BPCTCA target is 25 gal./Bbl. 1972 dollars.

- Notes: (1) For some refineries, it was necessary to use the "run on date" figure since capacities were missing from the data in Reference 8.
- (2) The flow reduction effect of converting barometric condensers to surface condensers was assumed by Brown & Root to be an average of 6.3 gal./Bbl.

TABLE III-7
INVESTMENT SUMMARY -
121 LARGE REFINERIES
ON CURRENT STUDY BASIS
(MM\$)

BPCTCA	In-Plant			End-of-Pipe Treating			Totals
	Convert	Misc. Flow	Other	Treatment	Sludge	Aux.	
	OTCW	Reductions	In-Plant (1)	Processes	Handl.	Facil.	
Class A	3	1	6	4	4	1	19
Class B	47	138	57	73	45	25	385
Class C	76	25	52	56	23	26	258
Class D	18	9	19	15	10	10	81
Class E	56	10	52	78	26	34	256
Totals	200	183	186	226	108	96	999

	<u>In-Plant Wastewater Flow Reduction(2)</u>	<u>End-of-Pipe Treating</u>		
		<u>Treatment Processes</u>	<u>Sludge Handl.</u>	<u>Totals</u>
<u>BATEA</u>				
Class A	2	5	1	8
Class B	27	76	9	112
Class C	19	60	6	85
Class D	9	26	2	37
Class E	<u>15</u>	<u>57</u>	<u>6</u>	<u>78</u>
Totals	72	224	24	320

Basis: Area 3, 1972 \$.

- (1) Includes sour-water stripping, storm-water handling, conversion of barometric condensers, and collection of multiple effluents.
- (2) Includes recycling of cooling tower blowdown and effluent treatment for reuse.

TABLE III-8
SAMPLE INVESTMENTS -
SMALL REFINERIES (M\$)

EPA Cat.	Crude Cap., B/yr	In-Plant			End-of-Pipe Treating		Totals
		Eliminate OTCW	Misc. Flow Reductions	Other In-Plant (1)	Treatment Processes	Sludge Handling	
BPCTCA							
A	2,200	-	2	-	129	111	242
	4,000	-	3	360	159	159	681
	5,000	-	-	54	163	109	326
	5,200	-	-	255	47	20	322
	10,000	395	-	377	394	275	1,441
	10,400	-	634	430	415	282	1,761
B	2,500	-	340	217	146	181	884
	3,500	-	278	416	190	221	1,105
	5,500	-	*	412	80	-	492
	5,500	312	123	372	265	290	1,362
	10,400	-	774	553	493	425	2,245

EPA Cat.	Crude Cap., B/SD	In-Plant	End-of-Pipe Treating	Totals	
		Wastewater Flow Reduction(2)	Sludge Handling		
BATEA					
A	2,200	94	97	34	225
	4,000	135	146	48	329
	5,000	63	120	9	192
	5,200	-	38	-	38
	10,000	165	265	84	514
	10,400	247	280	86	613
B	2,500	113	125	62	300
	3,500	140	156	75	371
	5,500	152	212	99	463
	5,500	183	212	99	494
	10,400	275	325	145	745

Basis: Area 3, 1972 \$.

* Less than \$1,000.

- (1) Includes sour-water stripping, storm-water handling, conversion of barometric condensers, and collection of multiple effluents.
 (2) Includes recycling of cooling tower blowdown and effluent treatment for reuse.

TABLE III-9
TOTAL INVESTMENT - ALL SMALL REFINERIES

	EPA Subcat.	No.	Capacity, MB/SD		Investment	
			Total	Avg.	M\$	\$/B/D
<u>BPCTCA</u>						
	A	42	205.8	4.9	29,246	142
	B	11	64.3	5.8	13,900	216
Totals -		53	270.1	5.1	43,146	160
<u>BATEA</u>						
	A	42	205.8	4.9	11,710	57
	B	11	64.3	5.8	5,418	84
Totals -		53	270.1	5.1	17,128	63
<u>TOTAL</u>						
	A	42	205.8	4.9	40,956	199
	B	11	64.3	5.8	19,318	300
Totals -		53	270.1	5.1	60,274	223

Basis: Area 3, 1972 \$.

Note: The only subcategory-D (Lubes) refinery with less than 10 MB/SD capacity has been included in Category B for these computations.

TABLE III-10
INVESTMENTS FOR NEW CAPACITY

<u>Year</u>	<u>MMS</u>		<u>Total</u>
	<u>Grass Roots</u>	<u>Expansions</u>	
1974	-	35	35
1975	6	27	33
1976	24	62	86
1977	12	21	33
1978	18	74	92
1979	16	27	43
1980	-	41	41
1981	16	27	43
1982	-	41	41
1983	-	41	41
Totals	92	396	488

Basis: Area 3, 1972 \$.

Assumptions:

- Expansions prior to 1978 will be designed to meet BPCTCA guidelines. The added investment to meet BATEA guidelines will be expended uniformly from 1978 through 1983.
- Expansions after 1977 will be designed to meet BATEA guidelines.
- All new refineries will be designed for BADT flow and BPCTCA technology, plus activated carbon adsorption.

TABLE III-11
DIRECT OPERATING COSTS FOR
121 LARGE REFINERIES

<u>Cost Associated With -</u>	<u>% of Investment</u>	<u>Investment MM\$</u>	<u>MM\$ / Year</u>		
			<u>In 1977</u>	<u>Increment for BATEA</u>	<u>Total In 1983</u>
Elimination of OTCW	N/A	200	5	-	5
Miscellaneous Flow Reductions	15.0	183	27	-	27
Sour-Water Stripping	48.8	40	20	-	20
Storm-Water Handling	5.0	125	6	-	6
Per. Cond./Mult. Eff.	10.0	21	2	-	2
Equalization	5.0	30	2	-	2
Dissolved Air Flotation	18.9	34	6	-	6
Activated Sludge	17.3	90	16	-	16
Filtration	18.9	29	5	1	6
Conting. & Sewer Revisions	0.0	47	0	-	0
Sludge Handling	25.0	131	27	6	33
Auxiliary Facilities	11.0	96	11	-	11
Recycle of CT Blowdown	11.0	11	-	1	1
Effluent Treatment/Reuse	5.0	61	-	3	3
Carbon Adsorption	17.2	195	-	34	34
Reuse Handling	5.0	27	-	1	1
Totals		1,320	127	46	173

Basis: Area 3, 1972 \$.

Source: Percentages were adopted or estimated based on data in Reference 2.

IV. CONTROL OF AIRBORNE EMISSIONS

A. Background and Scope

Three major categories of airborne emissions were selected for study:

- Hydrocarbon emissions from storage tanks, API separators, and loading racks
- Carbon monoxide and particulate emissions from catalytic cracking units
- Sulfur oxide emissions from combustion of gaseous fuels and from Claus sulfur plant effluent

Information pertinent to each of these sources is presented sequentially under each report topic. The control of sulfur oxide emissions from liquid fuels is included in Section V.

B. Summary

The control areas covered in this report include direct Federal new source regulation along with state regulation of existing facilities and some new facilities which are not federally controlled. The state regulations were suggested by EPA when State Implementation Plans were being developed.

The total investment requirements over the period 1974 through 1983 and the total annual costs of these regulations for 1983 are summarized below:

	Investment (\$MM)	Annual Costs (\$MM)
Hydrocarbon Control		
Tankage	75.3	(9.8)
API Separators	24.3	(19.4)
Loading Racks	66.2	(0.3)
Sub-Total	165.8	(29.5)
Catalytic Cracking Control		
Carbon Monoxide	218.2	(70.0)
Particulates	217.5	68.0
Sub-Total	435.7	(2.0)
Sulfur Oxide Control		
Fuel Gas Burning	325.7	(17.4)
Sulfur Recovery Plants	352.8	123.3
Sub-Total	678.5	105.9
Total	1,280.0	74.4

Yearly investments and costs are shown in Tables IV-1 and IV-2, respectively.

In addition to overall industry effects, we investigated the effect of refinery size. The following table illustrates that the unit investment cost becomes much greater as the refinery size decreases:

Refinery Size, B/SD	<u>10,000</u>	<u>61,900</u>	<u>200,000</u>
<u>Investment, \$MM</u>			
Hydrocarbon Control			
Tankage	0.72	1.88	4.85
API Separator	0.03	0.08	0.17
Loading Racks	0.14	0.22	0.32
Sub-Total	0.89	2.18	5.34
Catalytic Cracking Control			
Carbon Monoxide	0.92	2.76	5.57
Particulates	0.37	1.10	2.23
Sub-Total	1.29	3.86	7.80
Sulfur Oxide Control			
Fuel Gas Burning	0.71	2.31	4.94
Sulfur Recovery Plants	0.29	0.96	2.05
Sub-Total	1.00	3.27	6.99
Total	3.18	9.31	20.13
<u>Investment, \$/Bbl/Day</u>	318	150	101

Thus, the 10,000 barrel per day refinery experiences more than three times the investment requirement of a 200,000 barrel per day refinery on a barrel of capacity basis. As another point of perspective, the required investment for pollution abatement is essentially equal to the cost of a new atmospheric crude distillation unit for each of the refinery sizes.

Annual costs as a function of size were also determined:

Refinery Size, B/SD	<u>10,000</u>	<u>61,900</u>	<u>200,000</u>
<u>Annual Costs, \$M</u>			
Hydrocarbon Control			
Tankage	61.4	(258.0)	(1,113.6)
API Separator	(6.7)	(65.8)	(240.7)
Loading Racks	32.3	1.0	(117.1)
Sub-Total	87.0	(322.8)	(1,471.4)

Catalytic Cracking Control			
Carbon Monoxide	56.2	(526.6)	(2,702.0)
Particulates	112.2	341.0	703.7
Sub-Total	168.4	(185.6)	(1,998.3)
Sulfur Oxides Control			
Fuel Gas Burning	206.4	440.9	619.8
Sulfur Recovery Plants	110.9	335.2	725.4
Sub-Total	317.3	776.1	1,345.2
Total	572.7	267.7	(2,124.5)
Annual Costs, ¢/Barrel	16.5	1.2	(3.1)

The effect of refinery size on annual costs is even more dramatic than the investment effect.

While we feel that the values in this report give an accurate assessment of average industry effects, we caution that specific refineries may present significant deviations from the average. Some individual refiners may be affected even more severely than indicated by the above illustration. As an example, we know of a facility equipped with numerous small cone-roof tanks. These tanks are all much smaller than one would predict from industry statistics, thus compounding the economy-of-scale problem. While the tanks are structurally adequate, they have settled on their foundations and are out-of-round. Thus, even if the economies-of-scale problem could be overcome it would be impossible to equip these tanks with floating roofs. Similar individual problems exist in the other control areas.

C. Regulations

EPA has promulgated standards of performance for new or substantially modified storage tanks, fluid catalytic cracking unit regenerators and refinery fuel gas systems.⁽⁴⁾ New or substantially modified has been interpreted to mean any physical change in or change in method of operation which increases the emissions of any air pollutant or which results in emission of any new air pollutant.⁽⁵⁾ These regulations became effective on February 28, 1974, and they apply to facilities on which construction or modification began after June 11, 1973.

Storage vessels for crude petroleum, condensate and finished or intermediate refinery products with capacities greater than 40,000 gallons are covered by the regulation. A vapor recovery system or equivalent control is required for liquids with true vapor pressures greater than 11 psia. A floating-roof tank or equivalent control is required if tank contents have a vapor pressure between 11 and 1.5 psia. Products with vapor pressures less than 1.5 psia can be stored in conventional fixed-roof tanks. (The major products with vapor

pressures greater than 1.5 psia are gasoline, crude oil and naphtha-type jet fuel. Products such as kerosene, No. 2 fuel and heavy fuel oil all have vapor pressures less than 1.5 psia.) EPA has not issued any standards dealing with API separators or loading racks.

Carbon monoxide emissions are limited to a maximum concentration of 500 ppm (0.05% by volume) in the fluid catalytic cracking unit regenerator effluent gas. The opacity of effluent gases may not exceed 30% except for three minutes in any one hour. Particulate matter (catalyst fines) is also restricted to less than one kilogram per 1,000 kilograms of coke burned in the regenerator. If a carbon monoxide (CO) boiler is utilized along with supplemental liquid or solids fuels, the particulate standard is increased to account for the allowable particulates formed from the supplemental fuel. Provisions are made for temporarily exceeding the maximum opacity limit during periods of startup, shutdown or equipment malfunction.

Sulfur oxide emissions from the refinery fuel gas system are limited by prohibiting combustion of fuel gas with a hydrogen sulfide content greater than 0.1 grains per dry standard cubic foot. The fuel gas combustion system is defined to include process heaters, boilers and flares. Combustion of process upset gases in flares and operations involving fluid coking unit coke burner fuel gas and fluid catalytic cracking unit catalyst regenerator fuel gas are exempt. Facilities in which gases are burned to produce sulfur or sulfuric acid are also exempt. (Thus, sulfur recovery plants are not covered by the EPA regulations.)

In addition to specific new source performance standards, EPA also has influenced application of state controls to both new and existing refining facilities. In assisting in preparing State Implementation Plans, EPA suggested that states should consider both the above and additional emission limitations.⁽⁶⁾ Since existing facilities are controlled under the SIP's, this had the effect of extending EPA's regulations for new sources to existing refineries. The additional suggested limitations for hydrocarbons include vapor collection and disposal systems at truck and tank car loading racks, installation of vapor-control devices on API separators, equipping pumps and compressors handling volatile organic compounds with mechanical seals, and incineration of waste gas streams. Limiting emissions of sulfur oxides from sulfur recovery plants to a level of 0.01 pound per pound of sulfur processed was also suggested.

In order to determine the degree of acceptance of EPA's suggestions in current SIP's, we selected a representative sampling of refinery pollution-control practices. The areas included California, Kansas, Oklahoma, Texas, Louisiana and Illinois. As of January 1, 1974, these states included 51% of the U.S. refineries and 65% of the refining capacity. Summaries of the information obtained from the state plans are shown in Tables IV-3A, IV-3B and IV-3C for hydrocarbons, catalytic cracking units, and sulfur oxides, respectively.⁽⁷⁻¹⁵⁾

Except for the Midwest, state hydrocarbon regulations apply to both new and existing facilities. All states have enacted essentially the same regulation for storage tanks as EPA's new source performance standard. In addition, most of the states have specified controls for loading racks, API separators, and burning of waste gases. However, we know of no installations in which significant quantities of hydrocarbon waste gases are continuously emitted without burning because of safety considerations.

For purposes of this report, then, all new refineries are assumed to be built with floating-roof tanks for gasoline, crude oil and naphtha jet fuel. Vapor recovery facilities are provided at tank car and tank truck loading racks. API separators include hydrocarbon recovery facilities. We also forecast that all existing refineries not already in compliance will upgrade their facilities with respect to these control areas over the five year period 1974-1978.

State regulations for catalytic cracking units apply to both new and existing units in most cases. Unlike EPA's standard, the state regulations apply to catalytic cracking units or petroleum processes; they are not limited to fluid catalytic cracking units. Thus, Thermoform and Houdriform catalytic cracking units are included under the state regulations.

Both carbon monoxide and particulate emission standards are expressed in several ways. Carbon monoxide is limited by specifying a total yearly emission rate, a maximum concentration, or specifying that secondary combustion must be utilized. Particulates are controlled by imposition of opacity (or Ringleman) limits and hourly emission rates based on "process weight tables". The practical effect is to require addition of controls to existing units for both carbon monoxide and particulates.

Based on these considerations, we provided that all new catalytic cracking facilities will include equipment to limit both carbon monoxide and particulate emissions to the specified Federal levels. We also assumed that all existing catalytic cracking units which are not in compliance with respect to carbon monoxide and particulates will add facilities to achieve compliance. Addition of the necessary equipment to all existing units is forecast by 1978.

State sulfur oxide regulations also generally cover existing facilities, both for refinery fuel gas and sulfur recovery plants. Again the state regulations are stated in a variety of ways. Sulfur oxide emissions from refinery fuel gas systems are limited by ground level concentrations, exhaust gas concentrations or specific limits on hydrogen sulfide concentration in the fuel gas system. Sulfur recovery plant controls range from concentration limits in the exhaust gas to hourly emission limitations which are a function of stack heights.

We have assumed that all new refineries will be equipped with amine scrubbing facilities capable of producing refinery fuel gas with a maximum hydrogen sulfide content of 0.1 grains per dry standard cubic foot. The refinery will also be equipped with a sulfur recovery plant to convert the hydrogen sulfide removed from the refinery fuel gas into sulfur. The sulfur recovery plant will be equipped with a tailgas treating unit capable of effecting an overall sulfur recovery of 99.5%. We have also assumed that all non-complying existing refineries will install the same equipment over the five-year period 1974-1978.

D. Control Technology

The control technology for minimizing emissions from storage tanks is straightforward and well established. In the case of existing tanks, an internal floating roof can be installed inside the cone-roof tank. For new installations, either an internal or external floating roof (depending on local climatic conditions) can be supplied in the initial construction. Technology for controlling vapors at loading racks through absorption of hydrocarbons from the hydrocarbon air mixture is also relatively straightforward. This system involves collecting the vapor with a vapor recovery loading arm. The recovered vapors are then compressed and absorbed in a special vapor recovery unit. Control of emissions from API separators consists of installing a floating cover on the API separator. Several different types of covers and cover materials have been utilized.

Carbon monoxide emissions from catalytic cracking units can be controlled in two ways. The regenerator can be equipped with materials necessary to withstand high-temperature regeneration in the area of 1,300 to 1,500°F. At these temperatures, carbon monoxide is essentially all converted to carbon dioxide. The second method is to burn the carbon monoxide from conventional regenerators (1,000 to 1,200°F.) in a carbon monoxide boiler. The former method is relatively new and looks promising. The increased regenerator metallurgy cost is at least partially balanced by eliminating the need for a CO boiler and by increased performance of the catalytic cracking unit due to better catalyst regeneration. We provided for control of carbon monoxide by CO boilers. This should tend to give high values of investment and operating costs. Catalyst fines from a catalytic cracker can be controlled by additional cyclones, electrostatic precipitators or filters. Electrostatic precipitators are utilized in most cases and we have applied this type of equipment in this report.

Several processes exist for removing hydrogen sulfide from refinery gas and converting it to sulfur. Some of the processes accomplish this in a single step. For purposes of this report, we have utilized an absorption unit with diethanolamine as the absorption medium (amine plants). The recovered hydrogen sulfide is converted in a conventional Claus sulfur plant. The effluent from the Claus plant can also be treated by several processes. Since all of these are relatively new, we derived average levels of investment and operating costs for the various processes and used a hybrid process (tailgas plants).

E. Industry Characterization

There are no statistics which indicate the amount of construction yet to be performed by existing refineries to control hydrocarbon emissions. Inspection of the effective dates in Table IV-3A could lead one to conclude that most existing facilities have already installed the equipment covered in this report. However, we are acquainted with numerous existing plants which have not yet completed installation of all of the required equipment. The causes for the delay normally involve requirements for additional design and equipment procurement lead time. The delays are effected through variances granted by local authorities.

While it is difficult to arrive at a quantitative estimate of the current status of hydrocarbon emission control in existing refineries, we are confident that essentially all facilities in District V have installed this equipment. We have assumed that all existing refineries not located in District V will have to add controls. This treatment will tend to give high investment and operating estimates.

Based upon the assumption of total compliance in District V, criteria for additional base refinery controls then become: (16, 17)

	Percent in Districts I-IV
Refinery Capacity	83.7
Crude Oil Tankage	73.5
Gasoline Tankage	85.8
Naphtha Jet Fuel Tankage	66.9

A forecast of future petroleum demand and additional refinery capacity requirements is presented in detail in Section II and III. Table IV-4 summarizes this information with respect to forecast refinery capacity installations and additional gasoline and naphtha jet fuel production.

We assumed that 75% of both new and existing tankage for crude oil and jet fuel would have been constructed as floating-roof tankage in the absence of any pollution regulations due to the beneficial economic effect of increased product recovery. (18) For gasoline storage the recovery economics are better than for crude oil or naphtha jet fuel, and a base tankage distribution of 90% floating-roof tanks and 10% fixed-roof tanks was used for this product. (19)

Storage tank capacity at refineries for crude oil, finished gasoline, finished naphtha jet fuel and total unfinished oils are available from industry statistics. (17) In addition to finished products, unfinished components of both gasoline and naphtha-type jet fuel are also covered by the tankage regulations since their vapor pressures are generally greater than 1.5 psia. The total unfinished

oil volume in inventory as of September 30, 1973, was determined from Bureau of Mines statistics⁽²⁰⁾ for the U.S. refining industry. Unfinished oil inventories for Puerto Rico, Virgin Islands and Guam were estimated. The portion of the total unfinished oil inventory assignable to gasoline and naphtha jet fuel was determined on the basis of the proportion of the inventory of these products to total product inventories. A factor of two barrels of storage capacity per barrel of stored product was applied to the unfinished oil volume to determine the unfinished oil tankage in accordance with recent petroleum industry experience.⁽¹⁷⁾ These adjustments result in the following estimate of existing tankage at refineries as of January 1, 1974:

	<u>M Barrels</u>
Crude Oil	154,364
Finished Gasoline	191,209
Unfinished Gasoline	73,445
Total	<u>264,654</u>
Finished Naphtha Jet Fuel	7,785
Unfinished Naphtha Jet Fuel	3,359
Total	<u>11,144</u>

Neither distribution nor marketing facilities are included in this report. Focusing on storage at refineries, the following data were developed:^(16,17,21,22)

	<u>1970-1974 Growth Rate %/Year</u>	<u>Days of Crude Oil Capacity at 9/30/73</u>
U.S. Refinery Capacity	4.0	
U.S. Refinery Runs	4.1	
Crude Oil Storage at U.S. Refineries	4.4	10.1
U.S. Gasoline Production	3.3	
Finished Gasoline Storage at U.S. Refineries	3.3	12.8
U.S. Naphtha Jet Fuel Production	-10.9	
Finished Jet Fuel Storage at U. S. Refineries	-8.4	0.5

This shows that crude oil, gasoline and naphtha jet fuel tankage volumes at refineries have all grown at almost the same rate as the respective commodity to be stored. This indicates that refineries have reached the minimum tankage configuration.

Thus, historical trends were used to develop an estimate of additional tankage to be constructed at refineries. For crude oil, we estimated that storage capacity equal to 10.1 days of crude capacity would continue to be provided. (While increased storage may be required for increased delivery of imported crude in large tankers, we have assumed that this storage would be provided at deepwater terminals. Thus it would be included in the distribution system but would not affect refinery tankage facilities.) We utilized storage capacity for gasoline equal to 39.1 days of gasoline production, including both finished and intermediate tankage. The resulting aggregate amount of new tankage for each product through 1983 is as follows:

	<u>M Barrels</u>
Crude Oil	50,264
Finished Gasoline	49,970
Unfinished Gasoline	19,190
Total	<u>69,160</u>
Finished Naphtha Jet Fuel	0
Unfinished Naphtha Jet Fuel	0
Total	<u>0</u>

Existing crude oil tankage to be converted to floating-roof tankage was derived from the total installed tankage as of 1/1/74 combined with the 75% baseline factor and the previously derived 73.5% proportion which we estimate has not been converted. We estimated that this volume would be converted equally over the five-year period starting with 1974. The resulting volumes of existing crude oil tankage to be converted to floating-roof are summarized in Table IV-5. Additional crude oil tankage associated with new refinery construction is also shown. These volumes also reflect a 75% baseline factor. Existing gasoline tankage to be converted was determined using a factor of 90% for baseline control and a factor of 85.8% to reflect units not already converted. Again the conversion was assumed to be even over five years. Additional gasoline tankage was also estimated using a baseline factor of 90%. Existing naphtha jet fuel conversion to floating-roof was estimated with a baseline factor of 75% and a factor of 66.9% reflecting current conversion practice. No new naphtha jet fuel tankage is forecast, reflecting a zero product growth forecast.

Previous investigators⁽²³⁾ have estimated average size distributions for both crude oil and gasoline and naphtha jet fuel tankage. This gives a weighted average size of 80,400 barrels for crude oil tanks and 60,800 barrels for tanks containing gasoline and naphtha jet fuel.

No statistics are available for the number of loading racks at various refineries in the United States. While admittedly a simplification, we estimated that each refinery on the average has two loading racks - one for tank trucks and one for tank cars. We also assumed that this position would prevail for future refineries. The throughput was assumed to be 10% of refinery capacity for both existing and new refineries. In our opinion, no loading rack hydrocarbon recovery facilities would have been installed in the absence of pollution regulations. Thus, the baseline factor is zero. We do think that essentially all refineries in District V are in compliance with this regulation. The refinery capacity in District V was deducted in order to establish the amount of control still to be applied to existing refineries. We selected a refinery capacity of 61,900 barrels per stream day as our sample facility. This is the approximate average U.S. refinery size as of 1/1/74. This size was used for both existing and new refineries.

We were unable to locate any statistics which established baseline levels for installation of hydrocarbon recovery facilities on API separators. In our experience, very few refineries have moved to install this equipment. We do not think that facilities of this type would have been constructed in the absence of pollution controls. Thus, we used a baseline control level of zero. In terms of controls already applied to existing refineries, we utilized a conservatively large estimate by assuming that all existing refineries not located in District V would be required to add these facilities.

Unlike the hydrocarbon situation, some data on baseline industry characteristics are available for catalytic cracking units. An EPA survey in August 1971 indicated that 69% of the total domestic U.S. fluid catalytic cracking unit capacity was equipped with CO boilers and 20% had electrostatic precipitators.⁽¹⁹⁾ We assumed that the installed catalytic cracking capacity as of 1/1/74 is controlled to the same degree which will tend to overstate the required investment and operating cost to some degree.

The forecast of future petroleum demand in Section II indicates that the percentage yield of products heavier than distillate will remain essentially constant over the 1974-1985 timeframe. This suggests that no dramatic shift in utilization of gas oil conversion capacity as a proportion of crude charging capacity should be anticipated. As of 1/1/74, catalytic cracking capacity represented 31% of U.S. domestic refinery capacity.⁽¹⁶⁾ This value has been used in this report. A summary of forecast catalytic cracking capacity additions is included in Table IV-4.

A total catalytic cracking capacity as of 1/1/74 of 4,667 MB/D was developed from industry statistics.^(16,24) Using this capacity and a baseline installation factor of 69% enabled us to estimate the existing catalytic cracking unit capacity as of 1/1/74 which will

have CO boilers installed in the future. We have assumed that these installations occur linearly over the five-year period 1974-1978. The resulting catalytic cracking unit capacities are summarized in Table IV-5. Likewise, utilizing the forecast catalytic cracking unit capacity additions from Table IV-4 and the 69% baseline factor, the amount of new catalytic cracking unit capacity to be equipped with CO boilers as a pollution-control measure can also be derived. These volumes are also summarized in Table IV-5.

Using the 1/1/74 installed capacity and the assumption that 29% of this volume is equipped with precipitators leads to the volumes yet to be equipped shown in Table IV-5. In this case, we have also assumed that the precipitators would be installed over the five-year period 1974-1978 in a uniform pattern. Additional capacity which will also be equipped precipitators is shown in Table IV-5. These values were obtained from the forecast of additional catalytic cracking capacity in Table IV-4. In both cases, a baseline factor of zero was used since installation of a precipitator is essentially all attributable to pollution control.

The current average catalytic cracking unit size is 31,100 barrels per stream day. We have utilized this average value in developing the unit costs in this report. This tends to understate to some extent the cost involved in installing CO boilers and precipitators on existing equipment since the units yet to be converted tend to be smaller than the average size. On the other hand, it tends to overestimate the cost for new refining units since these units would probably have a capacity greater than the average value.

Statistics exist which establish the number of refineries which are equipped with amine absorption units or other equivalent processes for the removal of hydrogen sulfide from refinery fuel gas. However, removal of this material has beneficial effects for the refiner in terms of personnel safety and furnace corrosion. We estimate that essentially all U.S. refineries are equipped with amine scrubbing facilities. The exceptions would be small refineries utilizing sweet crude with low intensity processing. For purposes of this report, we assumed that 95% of the existing refinery capacity is equipped with amine absorption facilities. We have also adopted this value as the baseline control criteria. Some existing amine plants will have to be upgraded to achieve lower levels of hydrogen sulfide in refinery fuel gas systems. To approximate this effect, we reduced the baseline factor to 85%. In effect, we are forecasting that sums equivalent to replacing approximately 10% of existing capacity will be sufficient to upgrade existing plants to new performance levels.

Other investigators have determined that the average crude mix processed in the United States refineries in 1970 was 30°API with a sulfur content of 0.92 weight percent.⁽²⁵⁾ We have applied these values to industry capacity as of 1/1/74. A recovery factor in the

fuel gas of 70% of the sulfur in the incoming crude oil was utilized.⁽¹⁹⁾ These assumptions led to the estimate of existing amine plant capacity to be controlled above baseline capacity shown in Table IV-5. We assumed that the capacity to be converted as of 1/1/74 would be installed evenly over the period 1974 through 1978.

Amine plants associated with new refinery construction are also shown in Table IV-5. In this case, we assumed that crude utilized in new refining capacity would have a sulfur level of 2.0 weight percent, reflecting higher sulfur contents of Arabian Gulf crudes. We continued to use a 95% baseline factor and to assume that 70% of the sulfur in the incoming crude would be removed into the fuel gas system. We again selected an average refinery size of 61,900 barrels per stream day for both existing and new refineries.

A study conducted for EPA established the individual location and capacity of Claus sulfur recovery plants utilized by petroleum refineries as of mid-1972.⁽²⁶⁾ We combined this data with industry statistics for individual refinery locations and capacities^(27,28) to derive the listing of refineries and sulfur plants in Table IV-6. This indicates that approximately 8.5 million barrels per day of refining capacity, or about 61% of industry capacity, was equipped with sulfur recovery facilities. We have extrapolated the percentage of industry capacity which is equipped with sulfur recovery facilities to the 1/1/74 timeframe to approximate the existing capacity which is not equipped with sulfur recovery facilities. We feel that this gives conservatively high values of investment and operating costs. A baseline factor of zero was applied.

We used the same assumptions relative to crude gravity, crude sulfur content and recovery factor of hydrogen sulfide as were utilized in developing the amine plant capacity requirements. These factors, along with the survey value of 61% for industry capacity equipped with sulfur plant facilities, lead to the additional plant capacity requirements shown in Table IV-5. Capacity requirements for Claus plants associated with new refineries are also shown in this table.

A survey by other investigators⁽²⁹⁾ identified installed capacity of approximately 964 metric tons per day of Claus plant tailgas treating facilities as of 1974. We assumed that all other existing Claus plants as of 1/1/74 would require installation of tailgas cleanup facilities. We also assumed that all new plants would be built with this equipment. In our opinion, none of these facilities would have been added in the absence of pollution-control regulations. Therefore, we have utilized a baseline factor of zero.

In developing the capacity requirements shown in Table IV-5, we used the same assumptions relative to crude gravity, crude sulfur content, and recovery factor of hydrogen sulfides as we had previously utilized in developing the amine plant capacity requirements. An average refinery size of 61,900 barrels per stream day was selected for both new and existing refineries.

F. Investments

The differential investment for building a floating-roof tank and the cost of converting an existing cone-roof tank have been estimated by several investigators.^(1,30,31) Values from these sources were adjusted to the desired mid-1974 cost basis and utilized to obtain the investment values included in Table IV-7. Unit costs from this table were then combined with the tankage volumes to be controlled to arrive at the overall industry effects summarized in Table IV-1.

Typical investments for API separator modifications are presented in Table IV-8. We were guided in developing these estimates by consideration of previous investigations and reported installation data.^(1,32) The values in Table IV-1 were obtained using these unit costs. Investment values for vapor recovery facilities in Table IV-9 were estimated based upon results reported by industry investigators.⁽¹⁾

Cost estimates for CO boilers were available from several sources.^(19,33,34) Utilizing data in these studies and information in our files, we developed investment values based on the desired mid-1974 timeframe. The values shown in Tables IV-10 and IV-11 resulted. Data from other investigators were combined with information in our files to arrive at consensus values for precipitator investment.^(19,33) This information is shown in Tables IV-12 and IV-13. For existing units, we estimated that the required investment would be 20% greater than a grassroots unit for both CO boilers and precipitators.

Typical investment requirements for amine plants are shown in Table IV-14. These values were determined by surveying several other investigators' results combined with information in our files.⁽²⁶⁾ The values shown for Claus plants in Table IV-15 were derived in a similar manner. The same sources were also used for the Claus plant tailgas cleanup costs shown in Table IV-16.

G. Annual Costs

Maintenance costs for tanks, API separator modifications and vapor recovery systems were estimated at 2% of investment per year. Annual maintenance expenditures for other control equipment were set at 4% of investment. Taxes and insurance were estimated at 4% per year. An annual capital charge of 21.82% of investment was applied. This value is the before-tax sum required to obtain a 12% discounted cash flow rate of return on the total project investment with an income tax rate of 50%, 16-year life, and straight-line depreciation.

The product recovery figures for floating-roof tanks shown in Table IV-7 were estimated in accordance with standard industry procedures.^(35,36) The product values are based on products costs derived from incremental imported crude at the \$12.75/B acquisition cost which prevailed in the petroleum industry in mid-1974. Tank losses are quite sensitive to assumptions of vapor pressure, turnover rate and average liquid temperatures. The loss calculation

bases are summarized in Table IV-17. Cost variation with refinery size is shown in Table IV-18. This indicates that installation of floating-roof tanks is profitable except at small refinery sizes.

Product recovery estimates for API separators were derived from previous studies.^(1,32) Since the recovered material is recycled through the crude unit, a price of \$12.75 per barrel corresponding to the incremental mid-1974 foreign crude price was applied. Again values were developed for two refinery sizes in Table IV-8 in addition to the base facility in order to show the effect of refinery size. Installation of these facilities is profitable in all cases, but installation at the smaller refinery generates less profit on a unit basis.

Product recovery volumes for vapor recovery at loading racks shown in Table IV-9 were also taken from industry studies.⁽¹⁾ The product value approximates the cost of incremental petroleum products at mid-1974. Utilities (electricity and fuel) were estimated based upon similar facilities. Installation of vapor recovery at loading racks results in a cost to the smaller refinery and small credit to a large refinery.

Values for steam generation by CO boilers in Tables IV-10 and IV-11 were developed from literature correlations.⁽³⁴⁾ In using these correlations, we assumed a feed density of 300 pounds per barrel, 6 weight percent coke yield, and 90% line losses in the steam system. Seventy-five percent of the calculated steam generation was applied as a project credit. This was done to account for inefficiencies in heat level utilization and temporary steam system imbalances which would not allow full utilization of the steam from the CO boiler. Installation of a CO boiler is profitable for larger refineries, but becomes a cost item as refinery size decreases.

Utility requirements for the precipitator units shown in Tables IV-13 and IV-14 were derived from industry studies.^(19,33) Installation of this equipment results in a cost in all refinery sizes. The impact is greater for smaller facilities.

Utilities for amine plants in Table IV-14 and for Claus plants in Table IV-15 were estimated from consensus values.⁽²⁶⁾ Labor and supervision for the Claus plant was included at one-half man per shift at \$5.60 per hour with a 20% charge for supervision. A credit for sale of sulfur at a price of \$30.00 per long ton was utilized. The \$30.00 per long ton represents about 75% of the Gulf Coast loading port price as of mid-1974. The plant netback would be less than the Gulf Coast sales price due to transportation differentials. Again the effect of size can be seen from this data.

Tailgas unit operating expenses are shown in Table IV-16. Utilities were estimated from consensus values. Labor and supervision was included at one-fourth man per shift. Credit for sales of sulfur at \$30.00 per long ton was included. These units result in a cost in all size ranges.

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14. Regulations of the Air Control Commission, State of Louisiana, January 18, 1972.
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17. Petroleum Storage Capacity, National Petroleum Council, September 10, 1974.
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34. Alexander, W.H. and Bradley, R.L., "Can You Justify a CO Boiler?", Petroleum Refiner, Vol. 37, No. 8, pg. 107, August 1958.
35. Evaporation Loss from Fixed-Roof Tanks, American Petroleum Institute, Bulletin 2518, 1962.
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(SMM)

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TABLE IV-3A

STATE POLLUTION REGULATIONS FOR HYDROCARBONS

Area	Effective Date	Existing Facilities Exempt?	Controls Applied				
			Storage	Loading Racks	API Separator	Mechanical Seals	Burning Waste Gas
California	1/4/68	No	Yes	Yes	Yes	No	Yes
Kansas	1/1/72	Yes	Yes	No	No	No	Yes
Oklahoma	7/1/72	Yes (1)	Yes	Yes	Yes	Yes	Yes
Texas	12/31/73 (2)	No	Yes	Yes	Yes	No	Yes
Louisiana	1/18/72 (3)	No	Yes	Yes	Yes	Yes	Yes
Illinois	12/31/73 (4)	No	Yes	Yes	Yes	Yes	Yes

Notes: (1)

(2) Unless located in Air Quality Maintenance Area for hydrocarbons. Only applied in more populous counties and does not apply to crude oil production and transportation facilities.

(3) Crude oil and condensate facilities exempt.

(4) Illinois-produced crude oil exempt.

TABLE IV-3B

STATE POLLUTION REGULATIONS FOR CATALYTIC CRACKING UNITS

Area	Carbon Monoxide		Particulates	
	Effective Date	Existing Facilities Exempt?	Effective Date	Existing Facilities Exempt?
California	1/4/68	No	5/4/69	No
Kansas	1/1/72	Yes (as of 1/1/72)	1/1/71	No
Oklahoma	1/1/72	No	4/15/71	Yes (Until 10/15/72)
Texas	5/12/73	No	12/31/73	No
Louisiana	1/15/72	No	1/18/72	No
Illinois	12/31/73	No	New 12/31/72; Existing 5/30/75	No

Less than No. 1 Ringelman except for 3 mins in 1 hr. Process weight $\theta E = 4.1p0.67$. Less than 0.15 gr/DSCF.

Less than 20% opacity. Rapping allowed for 5 mins/hr. Process weight $\theta E = 4.1p0.67$ for less than 30 T/hr. and $E = (55)(p0.11) - 40$ when greater than 30 T/hr.

Less than No. 1 Ringelman. Rapping allowed for 5 mins/hr or 20 mins/day at No. 3 Ringelman. Process weight $\theta E = 4.1p0.67$ for less than 30 T/hr and $E = 55p0.11 - 40$ when greater than 30 T/hr.

Less than 20% opacity for units with construction begun after 1/31/72. Less than 30% opacity for existing. Rapping allowed for 5 mins/hr. or 6 hrs/10 days. Process weight $\theta E = 3.12p0.985$ for less than 20 T/hr. and $E = 25.4p0.287$ when greater than 20 T/hr.

Less than 20% opacity can be exceeded 4 mins/hr. Process weight $\theta E = 4.1p0.67$ for less than 30 T/hr. and $E = 55p0.11 - 40$ when greater than 30 T/hr.

Less than 30% opacity except for 8 mins/hr for 3 times in 24-hr. period. New sources process weight $\theta E = 2.54p0.534$ for less than 450 T/hr. and $E = 24.8p0.16$ when greater than 450 T/hr. Existing sources process weight $\theta E = 4.1p0.67$ for less than 30 T/hr and $E = 55p0.11 - 40$ when greater than 30 T/hr.

TABLE IV-3C

STATE POLLUTION REGULATIONS FOR SULFUR OXIDES

Area	Refinery Gas			Sulfur Recovery Plant		
	Effective Date	Existing Facilities Exempt?	Regulations	Effective Date	Existing Facilities Exempt?	Regulations
California	5/4/60	No	Ground level concentration of H_2S limited to 0.06 ppm (3 min. avg.) and 0.03 ppm (60 min. avg.). Ground level concentration of SO_2 limited to 0.5 ppm (60 min. avg.) and 0.04 ppm (24-hr. avg.) 300 ppm maximum concentration of SO_2 in exhaust gas.	11/5/70	No	Maximum sulfur emission equivalent to 0.08 gr. of H_2SO_4 per DSCF of exhaust gas.
Kansas	1/1/72	Yes (as of 1/1/72)	Maximum of 10 gr H_2S /100 DSCF.	- - No Specific Regulations - -		
Oklahoma	7/1/72	No	Ground level concentration of SO_2 limited to 0.46 ppm (60 min. avg.) and 0.05 ppm (24-hr. avg.).	7/1/72	Yes	Maximum of 20 lbs SO_2 per ton of sulfur processed.
Texas	3/5/72	No	Ground level concentration of H_2S limited to 0.08 ppm (30 min. avg.). Ground level concentration of SO_2 limited to 0.32 ppm (30 min. avg.).	3/5/72	No	Varies, depending on stack height.
Louisiana	1/18/72	No	Ground level concentration of SO_2 limited to 0.03 ppm (annual arith. mean) or 0.14 ppm (24-hr. avg.)	1/18/72	No	New - maximum SO_2 emission of 0.01 lb per lb of sulfur processed (1300 ppm). Existing - maximum SO_2 concentration of 2000 ppm.
Illinois	2/1/73	Yes (Until 5/30/75)	Maximum SO_2 concentration of 2000 ppm.	2/1/73	Yes	Maximum SO_2 concentration of 2000 ppm.

TABLE IV-4

FORECAST OF ADDITIONAL CAPACITY

INSTALLATIONS AND PRODUCTS PRODUCTION

[illegible]

TABLE IV-5
CAPACITIES TO BE CONTROLLED
(ABOVE BASELINE VOLUMES)

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
Tankage, M Barrels										
Crude Oil:										
Existing	5,673	5,673	5,673	5,673	5,673	-	-	-	-	-
Additional	1,727	1,447	3,591	1,303	1,823	535	535	535	535	535
Gasoline:										
Existing	4,541	4,541	4,541	4,541	4,541	-	-	-	-	-
Additional	954	954	954	958	782	782	383	383	383	383
Naphtha Jet:										
Existing	373	373	373	373	373	-	-	-	-	-
Additional	-	-	-	-	-	-	-	-	-	-
Catalytic Cracking Units, MB/SD										
CO Boilers:										
Existing	289.4	289.4	289.4	289.4	289.4	-	-	-	-	-
Additional	65.7	55.2	136.7	49.6	69.4	20.5	20.5	20.5	20.5	20.5
Precipitators:										
Existing	662.7	662.7	662.7	662.7	662.7	-	-	-	-	-
Additional	212.0	178.0	441.0	160.0	224.0	66.0	66.0	66.0	66.0	66.0
Sulfur Recovery Facilities, LT/SD										
Amine Plants:										
Existing	412.1	412.1	412.1	412.1	412.1	-	-	-	-	-
New	65.5	54.9	136.2	39.4	69.1	20.3	20.3	20.3	20.3	20.3
Claus Plants:										
Existing	1,060.5	1,060.5	1,060.5	1,060.5	1,060.5	-	-	-	-	-
New	1,310.0	1,097.4	2,723.4	988.2	1,382.8	406.0	406.0	406.0	406.0	406.0
Tailgas Plants:										
Existing	2,557.8	2,557.8	2,557.8	2,557.8	2,557.8	-	-	-	-	-
New	1,310.0	1,097.4	2,723.4	988.2	1,382.8	406.0	406.0	406.0	406.0	406.0

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TABLE IV-6
REFINERY AND SULFUR PLANT CAPACITIES
(Mid-1972)

	<u>Crude</u> <u>(MB/D)</u>	<u>Sulfur</u> <u>(LT/D)</u>
Arkansas		
Monsanto - Eldorado	38.0	25
California		
Monsanto - Avon	-	132
Union Oil of California - Santa Maria	-	55
Allied Chemical - Richmond	-	200
Humble Oil & Refining - Benicia	95.0	270
Shell - Martinez	103.0	100
Union Oil of California - San Francisco	99.0	145
Allied Chemical - El Segundo	195.0	175
Atlantic Richfield - Wilmington	173.0	65
Continental Oil - Paramount	36.0	9
Fletcher Oil & Refining - Wilmington	15.3	7
Golden Eagle Refining - Torrance	7.0	4
Gulf Oil - Santa Fe Springs	52.0	30
Mobil Oil - Torrance	130.0	85
Powerine - Santa Fe Springs	30.0	20
Standard Oil of California - El Segundo	225.8	450
Texaco - Los Angeles	81.1	50
Union Oil of California - Wilmington	107.0	349
Sub-Total	1,349.2	2,146
Colorado		
Continental Oil - Denver	29.5	18
Delaware		
Getty Oil - Delaware City	150.0	375
Hawaii		
Dillingham Petroleum - Barbers Point	35.5	50
Illinois		
Anilin Co. of Illinois - Wood River	103.7	150
Marathon Oil - Robinson	116.9	40
Mobil Oil - Joliet	164.0	300
Union Oil of California - Lemont	147.4	79
Sub-Total	532.0	569
Indiana		
American Oil - Whiting	295.1	279
Atlantic Richfield - East Chicago	140.0	85
Sub-Total	435.1	364

TABLE IV-6 (CONTINUED)

	Crude (MB/D)	Sulfur (LT/D)
Kansas		
Farmland Industries - Coffeyville	34.5	6
Phillips Petroleum - Kansas City	89.5	38
Sub-Total	124.0	44
Louisiana		
Cities Service - Lake Charles	237.5	100
Gulf Oil - Belle Chasse	170.0	40
Humble Oil & Refining - Baton Rouge	441.5	310
Stauffer Chemical - Baton Rouge	-	30
Shell Oil - Norco	250.0	40
Texaco - Paradis	152.6	50
Sub-Total	1,251.6	570
Michigan		
Leonard Refineries - Alma	33.5	12
Marathon Oil - Detroit	57.4	69
Sub-Total	90.9	81
Minnesota		
Great Northern Oil Co. - Pine Bend	95.0	130
Northwestern Refining Co. - St. Paul Park	54.5	40
Sub-Total	149.5	170
Mississippi		
Gulf Oil - Purvis	30.0	30
Chevron - Pascagoula	285.0	25
Sub-Total	315.0	55
Missouri		
American Oil - Sugar Creek	100.2	80
Montana		
Farmer's Union Central Exchange - Laurel	33.0	28
Montana Sulfur & Chemical Co. - East Billings	48.0	120
Montana Sulfur & Chemical Co. - Billings	46.0	85
Sub-Total	127.0	233
New Jersey		
Anilin Co. of New Jersey - Perth Amboy	82.5	50
Amerada Hess - Port Reading	75.0	40
Humble Oil & Refining - Linden	277.0	300
Freeport Sulfur - Westville	95.8	30
Mobil Oil - Paulsboro	97.8	185
Sub-Total	628.1	605

TABLE IV-6 (CONTINUED)

	Crude (MB/D)	Sulfur (LT/D)
New York		
Ashland - Buffalo	61.0	50
Ohio		
Ashland Oil - Canton	61.0	50
Sun Oil - Toledo	118.0	39
Sub-Total	179.0	89
Pennsylvania		
Atlantic Richfield - Philadelphia	165.0	73
BP Oil Corp. - Marcus Hook	105.0	52
Gulf Oil - Philadelphia	174.0	135
Sun Oil - Marcus Hook	176.0	30
Sub-Total	620.0	290
Texas		
Sulpetro Corp. - Big Spring	60.0	10
Diamond Shamrock - Sunray	47.5	30
Phillips Petroleum - Borger	97.4	33
Coastal States Petrochemical - Corpus Christi	138.4	85
Phillips Petroleum - Sweeny	89.5	25
Atlantic Richfield - Houston	220.0	30
Signal Oil & Gas - Houston	63.0	50
Shell Oil - Deer Park	274.0	400
Stauffer Chemical - Baytown	362.5	191
Atlantic Richfield - Port Arthur	-	73
BP Oil Corp. - Port Arthur	68.0	35
Mobil Oil - Beaumont	350.0	50
American Petrofina - Mount Pleasant	26.5	16
Gulf Oil - Port Arthur	319.0	150
Sub-Total	2,115.8	1,178
Utah		
Chevron - Salt Lake City	46.0	12
Virginia		
American Oil - Yorktown	51.8	50
Wisconsin		
Murphy Oil - Superior	35.3	15
Wyoming		
Atlantic Richfield - Sinclair	33.7	26
TOTAL	8,498.2	7,095

TABLE IV-7
UNIT COSTS FOR BUILDING OR
CONVERTING TO FLOATING-ROOF TANKS

	<u>New Tank</u>		<u>Convert Existing Tank</u>		
	<u>Crude Oil</u>	<u>Gasoline</u>	<u>Crude Oil</u>	<u>Gasoline</u>	<u>Naphtha Jet Fuel</u>
Liquid Stored					
Tank Size, Barrels	80,400	60,800	80,400	60,800	60,800
Investment, \$	61,000	51,000	85,000	74,000	74,000
Product Recovery, Bbls/Year	2,400	1,950	2,400	1,950	430
Product Value:					
\$/Barrel	12.75		12.75		
¢/Gallon		37.7		37.7	33.6
<u>Annual Costs, \$</u>					
Maintenance	1,220	1,020	1,700	1,480	1,480
Taxes & Insurance	2,440	2,040	3,400	2,960	2,960
Capital Charge	13,310	11,130	18,550	16,150	16,150
Product Recovery Credit	(30,600)	(30,880)	(30,600)	(30,880)	(6,070)
Total	(13,630)	(16,690)	(6,950)	(10,290)	14,520

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TABLE IV-8
TYPICAL COST OF API SEPARATOR MODIFICATIONS

Refinery Size, B/SD	<u>10,000</u>	<u>61,900</u>	<u>200,000</u>
Investment, \$	27,800	82,800	167,300
Product Recovery, Bbls/Year	1,130	6,970	22,530
Product Value, \$/Barrel	12.75	12.75	12.75
<u>Annual Costs, \$/Year</u>			
Maintenance	560	1,660	3,350
Taxes & Insurance	1,110	3,310	6,690
Capital Charge	6,070	18,070	36,510
Product Recovery Credit	<u>(14,410)</u>	<u>(88,870)</u>	<u>(287,260)</u>
Total	(6,670)	(65,830)	(240,710)
Unit Cost, ¢/Bbl of Crude	(0.19)	(0.31)	(0.35)

TABLE IV-9
TYPICAL COST OF VAPOR RECOVERY AT LOADING RACKS

Refinery Size, B/SD	<u>10,000</u>	<u>61,900</u>	<u>200,000</u>
Investment, \$	144,000	224,000	320,000
Product Recovery, Bbls/Year	767	4,747	15,330
Product Value, ¢/Gallon	35.7	35.7	35.7
<u>Annual Costs, \$</u>			
Utilities	860	5,340	17,300
Maintenance	5,760	8,960	12,800
Taxes & Insurance	5,760	8,960	12,800
Capital Charge	31,420	48,880	69,820
Product Recovery Credit	<u>(11,500)</u>	<u>(71,180)</u>	<u>(229,860)</u>
Total	32,300	960	(117,140)
Unit Cost, ¢/Bbl of Crude	0.93	0	(0.17)

TABLE IV-10
UNIT COSTS FOR BUILDING A CO BOILER

	<u>New Unit</u>	<u>Existing Unit</u>
Catalytic Cracker Capacity, B/SD	31,100	31,100
Investment, \$MM	3.07	3.68
Steam Generation, MMBTU/Year	1.14×10^6	1.14×10^6
Steam Value, \$/MMBTU	2.67	2.67
<u>Annual Costs, \$</u>		
Utilities	99,400	99,400
Maintenance	123,000	147,000
Taxes & Insurance	123,000	147,000
Capital Charge	670,000	803,000
Steam Credit ⁽¹⁾	<u>(2,283,000)</u>	<u>(2,283,000)</u>
Total	(1,267,600)	(1,086,600)

Note: (1) 75% of steam generation applied as a credit.

TABLE IV-11
TYPICAL COST FOR ADDITION OF A CO BOILER
TO EXISTING CATALYTIC CRACKING UNITS

Refinery Size, B/SD	<u>10,000</u>	<u>61,900</u>	<u>200,000</u>
Catalytic Cracker Size, B/SD	3,100	19,200	62,000
Investment, \$MM	0.92	2.76	5.57
Steam Generation, MMBTU/Year	0.114 x 10 ⁶	0.704 x 10 ⁶	2.28 x 10 ⁶
Steam Value, \$/MMBTU	2.67	2.67	2.67
<u>Annual Costs, \$</u>			
Utilities	9,910	61,400	198,000
Maintenance	36,800	110,000	223,000
Taxes & Insurance	36,800	110,000	223,000
Capital Charge	200,700	602,000	1,220,000
Steam Credit	<u>(228,000)</u>	<u>(1,410,000)</u>	<u>(4,566,000)</u>
Total	56,210	(526,600)	(2,702,000)
Annual Costs, ¢/Barrel	1.6	(2.5)	(3.9)

TABLE IV-12

UNIT COSTS FOR CATALYTIC CRACKING UNIT PRECIPITATORS

	<u>New Unit</u>	<u>Existing Unit</u>
Catalytic Cracker Capacity, B/SD	31,100	31,100
Investment, \$MM	1.23	1.47
<u>Annual Costs, \$</u>		
Utilities	19,400	19,400
Maintenance	49,200	58,800
Taxes & Insurance	49,200	58,800
Capital Charge	<u>268,000</u>	<u>321,000</u>
Total	385,800	458,000

TABLE IV-13
TYPICAL COST FOR ADDITION OF A PRECIPITATOR
TO EXISTING CATALYTIC CRACKING UNITS

Refinery Size, B/SD	<u>10,000</u>	<u>61,900</u>	<u>200,000</u>
Catalytic Cracker Size, B/SD	3,100	19,200	62,000
Investment, \$MM	0.37	1.10	2.23
<u>Annual Costs, \$</u>			
Utilities	1,930	12,980	38,700
Maintenance	14,800	44,000	89,200
Taxes and Insurance	14,800	44,000	89,200
Capital Charge	<u>80,700</u>	<u>240,000</u>	<u>486,600</u>
Total	112,230	340,980	703,700
Annual Costs, ¢/Barrel	3.2	1.6	1.0

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TABLE IV-14
TYPICAL COST OF AMINE PLANT ADDITIONS

	New	10,000	Existing	200,000
	61,900		61,900	
Refinery Size, B/SD				
Sulfur Level, Wt. %	2.0	0.92	0.92	0.92
Plant Size, LT/SD	119	8.8	54.5	176
Investment, \$MM	1.84	0.34	1.11	2.37
<u>Annual Costs, \$M</u>				
Utilities	437.4	32.3	200.3	646.9
Catalyst and Chemicals	9.9	0.7	4.5	14.6
Maintenance	73.6	13.6	44.4	94.8
Taxes & Insurance	73.6	13.6	44.4	94.8
Capital Charge	401.5	74.2	231.1	517.1
Total	996.0	134.4	524.7	1,368.2
Unit Cost, ¢/Bbl of Crude	4.6	3.9	2.4	2.0

TABLE IV-15
TYPICAL COST OF CLAUS PLANT ADDITIONS

Refinery Size, B/SD	New Refinery 61,900	Existing Refineries		
		10,000	61,900	200,000
Sulfur Level, Wt. %	2.0	0.92	0.92	0.92
Plant Size, LT/SD	119	8.8	54.5	176
Investment, \$MM	1.99	0.37	1.20	2.57
Annual Sulfur Production, LT	38,615	2,872	17,774	57,431
Sulfur Value, \$/LT	30.0	30.0	30.0	30.0
<u>Annual Costs, \$M</u>				
Utilities	109.7	8.2	50.4	163.0
Catalyst and Chemicals	3.9	0.3	1.8	5.7
Labor and Supervision	39.4	39.4	39.4	39.4
Maintenance	79.6	14.8	48.0	102.8
Taxes & Insurance	79.6	14.8	48.0	102.8
Capital Charge	434.2	80.7	261.8	560.8
Credit for Sulfur Sale	(1,158.5)	(86.2)	(533.2)	(1,722.9)
Total	(412.1)	72.0	(83.8)	(748.4)
Unit Cost, ¢/Bbl of Crude	(1.9)	2.1	(0.39)	(1.1)

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TABLE IV-16
TYPICAL COST OF CLAUS PLANT TAILGAS CLEANUP UNITS

	New Refinery	Existing Refineries		
	61,900	10,000	61,900	200,000
Refinery Size, B/SD				
Sulfur Level, Wt. %	2.0	0.92	0.92	0.92
Plant Size, LT/SD	119	8.8	54.5	176
Investment, \$MM	1.59	0.29	0.96	2.05
Annual Sulfur Production, LT	2,466	183	1,135	3,666
Sulfur Value, \$/LT	30.0	30.0	30.0	30.0
<u>Annual Costs, \$M</u>				
Utilities	133.8	9.9	61.6	198.9
Catalyst and Chemicals	3.7	0.3	1.7	5.5
Labor and Supervision	19.7	19.7	19.7	19.7
Maintenance	63.6	11.6	38.4	82.0
Taxes & Insurance	63.6	11.6	38.4	82.0
Capital Charge	346.9	63.3	209.5	447.3
Credit for Sulfur Sale	(74.0)	(5.5)	(34.1)	(110.0)
Total	557.3	110.9	335.2	725.4
Unit Cost, ¢/Bbl of Crude	2.6	3.2	1.6	1.0

TABLE IV-17
BASIS FOR ESTIMATING TANK LOSSES

Tank Parameters

Tank Size	<u>20,000</u>	<u>80,000</u>	<u>140,000</u>
Tank Dimensions	60 x 40	110 x 48	145 x 48
Average Outage	20	24	24
Paint Factor	1.0	1.0	1.0
Tank Type Factor	0.045	0.045	0.045
Seal Factor	1.00	1.00	1.00
Tank Content Factor:			
Crude Oil	0.75	0.75	0.75
Naphtha Jet Fuel	1.00	1.00	1.00
Gasoline	1.00	1.00	1.00
Reid Vapor Pressure:			
Crude Oil	5.0	5.0	5.0
Naphtha Jet Fuel	3.0	3.0	3.0
Gasoline	10.5	10.5	10.5
True Vapor Pressure ⁽¹⁾			
Crude Oil	3.1	3.1	3.1
Naphtha Jet Fuel	1.5	1.5	1.5
Gasoline	6.2	6.2	6.2
Turnover Rate ⁽²⁾			
Crude Oil	36.9	36.9	36.9
Naphtha Jet Fuel	6.4	6.4	6.4
Gasoline	9.3	9.3	9.3
Average Liquid Temperature, °F. ⁽³⁾	66	66	66
Average Daily Temperature Difference, °F. ⁽⁴⁾	18	18	18
Wind Velocity, MPH ⁽⁴⁾	10	10	10

Notes: (1) API Bulletin 2518.

(2) Based on average production and storage capacities.

(3) Average ambient temperature for Houston, Los Angeles, Oklahoma City, and Philadelphia plus 5°F. per API Bulletin 2518 recommendation.

(4) Average for Houston, Los Angeles, Oklahoma City and Philadelphia.

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TABLE IV-18
TYPICAL COST OF TANKAGE MODIFICATIONS

<u>Refinery Size, B/SD</u>	<u>10,000</u>	<u>61,900</u>	<u>200,000</u>
<u>Tanks to be Converted to Floating-Roof, Average Number and Size</u>			
Crude	5.0 @20,000 Bbls	7.8 @80,000 Bbls	14.4 @140,000 Bbls
Gasoline	8.9 @20,000 Bbls	13.7 @80,000 Bbls	25.3 @140,000 Bbls
Naphtha Jet Fuel	0.4 @20,000 Bbls	0.6 @80,000 Bbls	1.0 @140,000 Bbls
<u>Investment, \$M</u>			
Crude	252.5	664.3	1,717.0
Gasoline	451.7	1,165.1	3,012.0
Naphtha Jet Fuel	<u>18.2</u>	<u>47.0</u>	<u>121.6</u>
Total	722.4	1,876.4	4,850.6
<u>Investment, \$/Bbl/Day</u>	72.2	30.3	24.3
<u>Annual Cost, \$M/Year</u>			
Crude	31.8	(53.4)	-(285.1)
Gasoline	24.8	(214.2)	(848.8)
Naphtha Jet Fuel	<u>4.8</u>	<u>9.6</u>	<u>20.3</u>
Total	61.4	(258.0)	(1,113.6)
<u>Annual Costs, ¢/Barrel</u>	1.8	(1.2)	(1.6)

SECTION V. REFINED PRODUCT QUALITY REGULATIONS

A. Scope

The investment and operating cost effects imposed by two product quality regulations were examined in this study:

- Lead additive levels in motor gasoline.
- Residual fuel oil sulfur levels.

The restriction of unleaded gasoline sulfur level has been recently discussed but is not regulated at the time of this study and has been specifically excluded from consideration.

B. Conclusions

The investment and operating cost impacts of unleaded gasoline manufacture alone and in combination with a lead phasedown program have been approximated by updating studies completed by TM&S in 1972 (3,4) to a 1974 economic basis. Comparative investment and operating costs are shown below:

	Added Refining Industry Costs Incurred As A Result of Lead Regulations During the Period		
	1977	1980	1985
Cumulative Industry Investment, \$MM			
Unleaded Gasoline With Lead Phasedown	1,200	1,970	3,190
Unleaded Gasoline Alone	400	1,360	2,830
Added Annual Costs, \$MM			
Unleaded Gasoline With Lead Phasedown	330	420	690
Unleaded Gasoline Alone	60	220	540

The indicated 1985 investment in the higher case is expected to be well within the capability of the process construction industry but represents about twice the level of expenditure required to meet reference case growth requirements. Perhaps the most striking impact indicated in this effort is that small refiners (7,500 B/D) must endure an investment per barrel of gasoline production that is more than double that imposed on the refiners with capacity in excess of 100,000 barrels per day. The elimination of lead phasedown regulations is shown to primarily result in deferral of about

\$610 million of capital investment for the industry to the post-1980 period.

Residual fuel sulfur level restrictions by both Federal and state regulations are expected to result in an additional low-sulfur fuel oil demand of 400,000 barrels per day by 1977 and an additional 350,000 barrels per day by 1983. The indicated overall industry impacts are shown below:

	Additions During Time Period	
	1974-1977	1977-1983
Investment, \$MM	590	510
Annual Costs, \$MM	290	240

This analysis suggests that small refiners cannot efficiently compete in the desulfurized fuel market and will be forced to rely on low-sulfur feedstocks or compete for dwindling high-sulfur fuel oil customers.

C. Prior Lead Additive Studies

The original contract document specified that a new analysis of lead additive usage would be available for incorporation in this study. However, revisions to the scope of the analysis and priority reassignments have delayed the completion date past the deadline for this study. As a result, previously published analyses of this topic have been reviewed for adaptation to the current study criteria.

In 1971 The PACE Company completed a multi-client evaluation of lead additive regulations.⁽¹⁾ PACE employed nine separate mathematical models to describe the refining environment for the period 1970 to 1980. A major conclusion of the analysis was the expectation of a totally unleaded gasoline market by 1980. The total additional investment for the decade was estimated at \$4.3 billion on a 1970 Gulf Coast investment basis. The expected average added cost for motor gasoline was estimated at 1.3¢ per gallon.

EPA commissioned a study by Bonner & Moore Associates in 1971 to evaluate the impact of proposed lead additive controls.⁽²⁾ Bonner & Moore employed two mathematical refinery models and evaluated both the separate production of unleaded gasoline and a combination with several proposed lead phasedown schedules. The studies were all directed at a 1970 to 1980 time period. Bonner & Moore estimated investment requirements for unleaded gasoline production as \$1.5 billion by 1980, while lead phasedown (Schedule 0) was expected to add an additional \$1 billion. These values would be expected to vary from the PACE study since the Bonner & Moore analysis accounted for elimination of only 77% of the lead additives employed in 1970. One case analyzed in the Bonner & Moore study was premised on total lead

elimination, resulting in an investment requirement of \$3.5 billion, but was found to exceed construction industry capabilities.

Turner, Mason & Solomon completed a multi-client analysis of lead additive regulations in 1972.⁽³⁾ The TM&S study employed five mathematical refinery models to analyze the lead regulations in force at the time, including lead phasedown. Investments for the 1970-1980 time period were estimated as \$3.6 billion. Again this analysis covered elimination of less than 80% of the lead additive levels employed by the industry in 1970. Later in 1972, TM&S completed a study of unleaded gasoline production⁽⁴⁾ without the lead phasedown regulations. Added refinery investments were reduced to \$3.0 billion by 1980 with significant relief indicated in early years for small refiners.

In 1974 Arthur D. Little, Inc., completed Phase I of an EPA-sponsored update of lead additive restrictions on the refining industry.⁽⁵⁾ The ADL study employed a single mathematical model to prepare an overview of the industry impact to 1980, but the model was not validated against industry operating data. Added investment by 1980 was estimated at \$1.5 billion at 1974 investment levels. The Phase II ADL effort currently underway is expected to be substantially expanded in scope, but will still exclude consideration of the impact on small refiners.

Though all of the previously mentioned analyses addressed the topic at hand, none is appropriate for direct incorporation in this study.

- No single study covers the 1974-1983 period.
- Only ADL is based on 1974 investment costs.
- No study is based on current petroleum demand outlooks.
- None anticipated current lead phasedown considerations.

While the conclusions would only be approximate, it is possible to adapt the results of an earlier analysis to the current situation by adjustment of demand forecast, investment levels, lead removal rates, and extrapolation to later time periods. Such adjustments would require the availability of all details of the previous analysis. Since the only studies for which all detailed calculations are readily available to us are those previously completed by TM&S, we have elected to adapt them to the current study criteria.

D. Current Regulatory Outlook

In accordance with EPA regulations, essentially all gasoline marketers must offer an unleaded gasoline grade with a minimum quality rating of 91 Research Octane Number (RON). In addition, EPA had

promulgated lead phasedown regulations which have been suspended following a review by the Federal Courts. The rescinded regulations posed the following phasedown schedule:

<u>Effective Date</u>	<u>Average TEL Level, Total Gasoline Production (Grams/Gallon)</u>
1/1/75	1.7
1/1/76	1.4
1/1/77	1.0
1/1/78	0.8
1/1/79	0.5

Since the Federal Court ruling is currently under review, this analysis will consider the impact of unleaded gasoline both with and without companion lead phasedown regulations.

E. Analytical Techniques

The technique employed in the 1972 TM&S studies basically involved the following steps:

1. Five linear programming models were constructed to represent various industry sectors.
2. Historic industry operating data were imposed upon the models to validate process descriptions and blending data.
3. Forecast product demands were imposed on the models for the years 1974, 1977 and 1980 to determine investment and operating parameters in the absence of lead additive regulations.
4. Gasoline forecasts were revised to reflect the use of catalyst-equipped cars and lead phasedown regulations. These revised forecasts were then imposed on the models to determine investment and operating parameters required to satisfy EPA regulations.
5. A comparison of the reference and EPA-regulated environments indicated the investment, raw material consumptions and added operating costs imposed by lead additive regulations.

Thus, to adapt the 1972 studies to the current study criteria, the models must be reviewed, reference environment demand forecasts revised, gasoline forecasts updated, and all economic results must be converted to a 1974 basis.

The 1972 TM&S refinery models represented all industry capacity that produced gasoline in 1970. Those models are compared with indicated 1974 capacity from the previous study below:

Model	Location and Crude Rate Represented	1970 Model Capacity (B/D)	Forecast 1974 Model Capacity (B/D)
M-1	All Gasoline Refineries Less Than 15 MB/D	7,500	7,500
M-2	Gasoline Refineries 15 to 60 MB/D Excluding California	35,000	40,000
C-1	Gasoline Refineries 60 to 140 MB/D Excluding California	90,000	105,000
C-2	Gasoline Refineries More Than 140 MB/D Excluding Calif.	225,000	267,000
W-1	California Gasoline Refineries More Than 15 MB/D	85,000	90,000
Industry Capacity Represented		11,927,000	13,735,000

The 1974 forecast of 13,735,000 barrels of gasoline refining capacity plus the 700,000 barrels per day of actual 1974 specialty plant capacity shown on Table A-1 compares favorably with the actual domestic refining capacity reported by FEA for January 1, 1974, of 14,250,000 shown on Table A-4. While not an exact fit, this level of agreement suggests that the 1972 study may be adapted to approximate an analysis of the 1973 industry base.

The 1972 IM&S analyses were based upon substantially higher petroleum demand growth rates than those proposed in Section II of this study and detailed on Table A-2. However, the prior studies were also predicated on a substantial growth in future product imports, while the most recent NPC study projects a leveling off of product imports. A comparison of these bases indicates that capacity additions forecast for the reference environment for a current study would conform almost exactly to the projected increase forecast in the 1972 TM&S report.

	1972 TM&S Report		Current NPC Outlook	
	1974	1980	1974	1980
Domestic Petroleum Demand	17,606	22,400	16,735	20,096
Product Imports and Non-Refinery Supplies	(4,058)	(5,527)	(3,233)	(3,233)
Net Refinery Output	13,548	16,873	13,502	16,863

Thus, it appears that the reference case solutions from the prior study could be updated to 1974 economic bases and be reasonable approximations of the current NPC demand forecast.

Few investigators have agreed on the relative fuel economy to be assigned to automotive emission-control systems. For purposes of this analysis, we have assumed that catalyst systems will be employed in the future and that 1975 emission-control regulations will prevail throughout the time period. The fuel penalties assigned to various model year autos are shown below:

Model Year	Economy Loss Relative to 1970 Automotive Population, %
1971	6.5
1972	8.4
1973-1974	13.0
1975+	8.0

These estimates are based on weighted average vehicle performance attributed exclusively to emission-control systems.

With these fuel economy premises, new forecasts of gasoline demand for a reference environment (no auto emission controls) and a study case were prepared. Through a detailed analysis of changes in gasoline volumes and pool octane requirements developed in the 1972 studies, investment and operating cost indicators were developed for each individual refinery model. These indicators were combined with the study case gasoline forecasts and updated to 1974 economic bases to approximate the investment and operating cost effects to be anticipated for the period 1974 through 1983 from Federal lead additive regulations.

F. Determination of 1973 Industry Facilities

The 1973 domestic refining industry, for the most part, reflected the outlooks of the early 1970's for high gasoline demand growth rate and anticipated unleaded gasoline and lead phasedown programs. In practice, this resulted in a significant amount of excess gasoline manufacturing capacity in 1973 and 1974. For purposes of this analysis, we have assumed that all refiners under 20,000 B/D deferred octane improvement investments in anticipation of a short-term exemption from EPA regulations. We have also assumed 20% of the octane improvement investment requirements for refiners in the 20,000 to 70,000 B/D range was deferred to a later period. All other refiners were assumed to have invested in refining facilities at the rate forecast in the 1972 TM&S analysis.

G. Cost of Lead Additive Regulation Programs

After adapting investment and operating cost data to a 1974 cost basis as previously described, incremental raw material values were adjusted from the \$3.26 per barrel typical of 1970 imported crude cost to a marginal 1974 value of \$12.75 per barrel. Then a comparison of results for the case involving unleaded gasoline with lead phasedown to the forecast of requirements for the reference case yielded the additional investment pattern detailed on Table V-1 and summarized below:

	Cumulative Industry Investment To Be Incurred As A Result Of Lead Regulations In The Period 1974 Through 1985, MMS		
	1977	1980	1985
Facility Cost	920	1,520	2,460
Royalty and Catalyst	100	150	250
Interest and Owner's Cost	110	180	300
Working Capital	70	120	180
Total Capital Requirement	1,200	1,970	3,190

The \$3.2 billion investment to be expended over an 11-year period is expected to be well within the capability of today's process construction industry. The \$290 million average annual expenditure required by these regulations compares with an industry total capital addition for refinery modernization and expansion of \$950 million for the period 1968 through 1972.(11)

Of major importance in this analysis is the investment requirement as a function of refinery size:

<u>Model</u>	<u>1974 Capacity, B/D</u>	<u>1985 Gasoline Volume, B/D</u>	<u>Investment/Annual Barrel Gasoline, \$</u>
M-1	7,500	2,780	2.14
M-2	40,000	28,900	1.30
C-1	105,000	63,720	0.94
C-2	267,000	154,500	0.88
W-1	90,000	56,450	1.01

It is apparent that the investment burden associated with lead additive restriction falls unevenly in the industry. The smallest refiners must invest more than twice as much capital per barrel of gasoline as the over 100,000 B/D refiners.

Added refining costs resulting from the combination of unleaded gasoline and lead phasedown programs are detailed on Table V-2 and summarized below:

	<u>Added Refining Costs Above 1973 Reference Case, \$MM/Year</u>		
	<u>1977</u>	<u>1980</u>	<u>1985</u>
Revenue from Additional Gasoline Sales @37.7¢/Gallon	(2,260)	(3,070)	(4,190)
Byproduct Revenue	(320)	(410)	(550)
Raw Materials	2,700	3,500	4,770
Operating Costs (Including TEL)	(100)	(110)	(160)
Capital Charges	<u>310</u>	<u>510</u>	<u>820</u>
Net Added Cost	330	420	690

If all of these added costs are recovered as gasoline cost increases on the total 130 billion gallons of forecast 1985 gasoline sales, gasoline prices would be expected to rise by an average of about one cent per gallon. The anticipated impact upon refiners ranges from over 1.9¢ per gallon for refineries processing less than 20,000 B/D to less than 0.5¢ per gallon for refineries with capacity over 140,000 B/D.

The investment and added refining costs associated with unleaded gasoline requirements without lead phasedown regulations are shown on Tables V-3 and V-4 and summarized below:

	<u>1977</u>	<u>1980</u>	<u>1985</u>
Added Refining Industry Capital Requirements, \$MM	400	1,360	2,830
Added Refining Costs, \$MM/Year	60	220	540

As one would anticipate, the elimination of lead phasedown shows a substantial reduction in refining industry capital requirements in 1977. The smallest refiner modeled (M-1) is allowed to defer \$560,000 of capital investment by elimination of the lead phasedown regulations. Other segments of the industry which have essentially provided for initial lead phasedown investments by 1974 would also find a smaller investment requirement imposed by growing unleaded gasoline demands until after 1977. Even by 1980 added industry investment will be reduced by 31%, or \$610 million, by elimination of lead phasedown regulations. By about 1990, essentially all gasoline demand will be unleaded under the premises employed in this study, so the investment level and annual costs will ultimately show no effect of the lead phasedown regulation.

H. Residual Fuel Sulfur Regulations

EPA regulations expressly limit sulfur oxide emissions from major utility plants constructed after August 1971 to 0.8 pound SO₂ per million BTU's of oil fired. Assuming an average heat content of 6 million BTU's per barrel of residual fuel, this restricts fuel sulfur level to a nominal value of about 0.7 weight percent. However, in addition to the EPA new source performance standards, the states have established maximum fuel sulfur content regulations to insure that Federal ambient sulfur oxide standards are satisfied. The state standards call for widespread availability of fuel oil with 0.3 weight percent sulfur level for East Coast locations, 0.5 weight percent sulfur fuel in California, and levels varying from 1 weight percent to essentially unregulated levels for some existing facilities in other locations.

I. Historic Residual Fuel Oil Market

The reported residual fuel consumption for 1973 detailed on Table V-5 is summarized below:

	Total Volume (MB/D)	Distribution of Market By Sulfur Content, %		
		0 to 0.5	0.5 to 1	Over 1
PAD I	1,930	37	23	40
PAD II	250	4	44	52
PAD III	190	12	20	68
PAD IV	30	8	25	67
PAD V	420	55	6	39
Total U.S.	2,820	35	22	43

It may be noted that two-thirds of the total residual fuel consumption occurs on the East Coast (PAD I), where stringent state sulfur standards are currently being imposed. The other major fuel market (PAD V) had already achieved a large measure of control to 0.5% sulfur level by 1973. On a nationwide basis about one-third of all residual fuel was less than 0.5% sulfur, while almost one-fourth exceeded 2 weight percent sulfur content. An additional 120,000 barrels per day of residual fuel of varying sulfur levels was consumed in refinery operations in 1973.

J. Future Fuel Oil Markets

Only a detailed analysis of the effect of local regulations on each fuel consumer would indicate the outlook for future residual fuel sulfur levels. In the absence of such an approach, we have adopted the following assumptions to examine the effect of fuel oil regulations:

- All increased residual fuel volumes above the 1973 base level must conform to 0.7 weight percent sulfur levels.
- Residual fuel consumed by existing plants in Petroleum Administration for Defense District (PAD) I will meet the following schedule:

	0.3 or Less	0.3 to 0.7	Over 1
1977	45%	25%	30%
1983	55%	25%	20%

- By 1977, 65% of all PAD V residual fuel consumed by existing plants is assumed to meet an 0.5% maximum sulfur content standard.
- No major reductions in fuel sulfur level are forecast for existing plants in PADS II, III or IV.

- By 1977, 50% of the fuel oil consumed in refinery operations is assumed to be desulfurized to 0.7 weight percent.

The attached Table V-6 details residual fuel demand forecasts based on the NPC projections presented in Appendix Table A-2. The consideration of the Table V-6 forecast plus the assumptions regarding fuel regulations outlined above lead to the following fuel-sulfur projections:

	Residual Fuel Demand by Sulfur Level, MB/D			
	0.3 Wt. %	0.5 Wt. %	0.7 Wt. %	Over 1 Wt. %
1973 Actual	750	230	630	1,330
1977 Forecast	900	270	840	1,040
1983 Forecast	1,100	270	990	850

This forecast suggests that additional low-sulfur residual fuel demand directly attributable to Federal environmental regulations will total about 400,000 barrels per day between 1974 and 1977 and 350,000 barrels per day between 1977 and 1983.

This additional demand may be satisfied by increased processing of premium-priced low-sulfur crude oils, blending desulfurized distillate fuel oils with residual stock, or direct desulfurization of residual fuel. Low-sulfur crude processing and distillate blending are likely to predominate before 1980 simply because few residual desulfurization units are under construction. These practices represent extra-cost refinery operations, but do not require facility investments. Since the dominant supply of petroleum throughout the world is high in sulfur content (over 1% sulfur), we believe the premium for low-sulfur crudes and residual fuels will ultimately reflect the economics of residual desulfurization processes. Thus, we have elected to calculate industry impacts as if all new low sulfur fuel demand required desulfurization of residual fuel from marginal Arabian Light crude oil. We caution the reader to note that this overstates the actual refining investment to be committed by the domestic industry in the near term, but should approximate the correct annual costs incurred in satisfying environmental regulations.

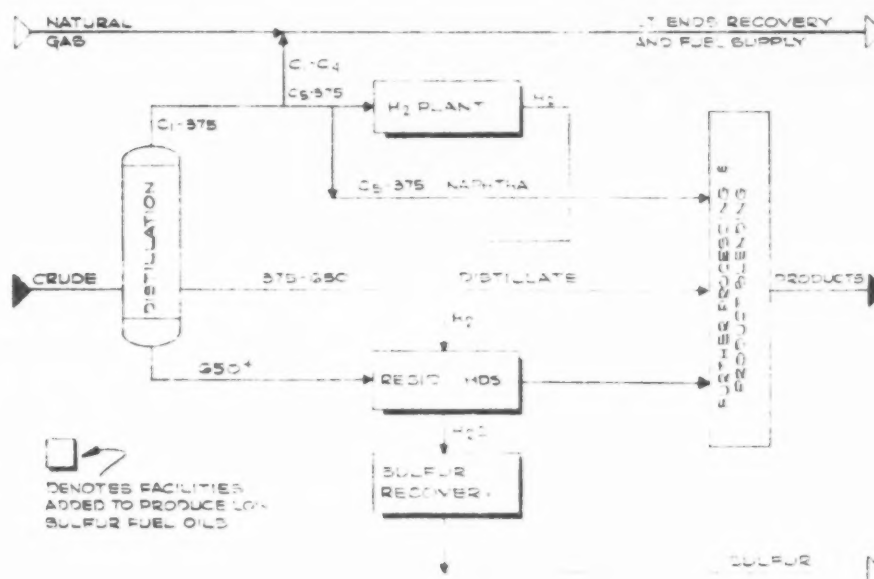
K. Fuel Oil Desulfurization Technology

The common feature of all fuel desulfurization processes is hydrogenation of the organic-sulfur compounds to hydrogen sulfide (H_2S) over a catalyst. Differences between processes relate primarily to catalysts used - i.e., susceptibility to feed contaminants and the tendency to crack rather than desulfurize the feed. Sulfur removal is accomplished by contacting the liquid feed with hydrogen

at elevated temperature and pressure and passing the resulting mixture downflow over a fixed-bed, trickle-flow reactor containing the catalyst. Recycle gas quenching is employed to moderate the exothermic temperature rise.

The costs employed in this study are based on desulfurizing a fuel oil cut (650°+) from Light Arabian crude. Four cases were developed to demonstrate the effects of capacity and product sulfur level. Refinery capacities of 200,000 B/CD and 30,000 B/CD were used to establish the effects of refinery throughput on costs. Fuel oil product sulfur levels of 0.7 weight percent and 0.3 weight percent were chosen to demonstrate the effects of severity on operating economics. The 0.7 weight percent approximates the sulfur level allowed by EPA new source SO₂ emission limits and the 0.3 weight percent represents the sulfur level required by several East Coast states.

The physical properties of Light Arabian crude are shown on Table V-7. The refinery configuration on which calculations are based is shown below:



Capital requirements were calculated for a hydrogen plant, sulfur recovery plant and HDS plant sized to effect the fuel oil sulfur limit. Then offsite investments, utility requirements, and other operating costs were estimated. These were all compiled to determine the cost of desulfurizing the fuel oil.

This approach changed the original refinery yields by:

- Consuming some C₅-375° naphtha as hydrogen plant feed.
- Changing the characteristics of the original 650°+ stream because of the small amount of cracking that took place in the HDS reactor.
- Requiring some 375-650°F. desulfurized distillate as blendstock with product fuel oil to meet sulfur specifications.

Investment estimates for the cases studied are detailed on Table V-8. Table V-9 relates annual capital charges and operating costs for the same cases. Both tables are summarized here:

Investment and Operating Costs

<u>Crude Run (MB/D)</u>	<u>Sulfur in Fuel Oil (Wt.%)</u>	<u>Investment Required (\$MM)</u>	<u>Cost to Desulfurize (\$/Bbl)</u>
200	0.7	108	1.77
200	0.3	146	2.08
30	0.7	25	2.35
30	0.3	35	2.84

Investments shown here include capital for the HDS process, hydrogen plant, sulfur recovery plant, and all associated offsites - in mid-1974 timeframe.

It is evident from this analysis that the small refinery is able to competitively desulfurize fuel oil. An evaluation of the capital requirements per barrel of crude and per barrel of HDS fuel further underscores this fact, as shown below:

<u>Crude Run (MB/D)</u>	<u>Fuel Oil Sulfur Specification (Wt.%)</u>	<u>Desulfurization Capital Required \$/B/D Crude Run</u>	<u>Capital Required \$/B/D HDS Feed</u>
200	0.7	540	1,210
200	0.3	720	1,630
30	0.7	830	1,560
30	0.3	1,100	2,460

L. Estimated Cost of Fuel Sulfur Regulations

Based on the technology analysis presented in the preceding section, we anticipate that all residual fuel desulfurization facilities

will be provided by large refiners either located within the U.S. territories or by export refiners fully committed to the domestic market. This assumption leads to the following projection of fuel oil desulfurization projects:

	Additions During Time Period	
	<u>1974-1977</u>	<u>1977-1983</u>
Desulfurization Capacity, MB/D:		
0.3 Wt.% Product	155	193
0.5 Wt.% Product	42	0
0.7 Wt.% Product	218	150
Investment Requirements, \$MM	590	510
Annual Costs, \$MM	290	240

It may be of interest to note that these estimated costs for desulfurization fall in the same range as is currently expected for flue gas desulfurization. Thus, if flue gas desulfurization technology is commercialized in the near term, some of the investment burden may be shifted from the petroleum refining industry to the electric utility industry. However, in either case, the costs imposed by fuel oil sulfur regulations are expected to be represented by the above estimates.

REFERENCES - SECTION V

1. The Effect of Unleaded Gasoline Production on the Refining and Petrochemical Industries, The PACE Company, Houston, Texas, February 1971.
2. An Economic Analysis of Proposed Schedules for Removal of Lead Additives from Gasoline, EPA Contract No. 68-02-0050, Bonner & Moore Associates, Inc., Houston, Texas, June 25, 1971.
3. The Economic Impact of Automotive Emission Standards, Turner, Mason & Solomon, Dallas, Texas, March 31, 1972.
4. The Impact of Alternate Lead Emission Control Programs, Turner, Mason & Solomon, Dallas, Texas, May 5, 1972.
5. Impact of Motor Gasoline Lead Additive Regulations on Petroleum Refineries and Energy Resources - 1974-1980, Phase I, EPA-450/3-74-032a, Arthur D. Little, Inc., Cambridge, Massachusetts, May 1974.
6. "Desulfurize Kuwait Reduced Crude", Hydrocarbon Processing, May 1973, page 89.
7. "Desulfurization Reactors Added to H-OIL Process", Oil & Gas Journal, June 1972, page 59.
8. "Ecologically Acceptable Fuels from the Gulf HDS Process", AIChE 67th Annual Meeting, December 1974.
9. "Pilot Plant Proves Resid Process", Hydrocarbon Processing, May 1973, page 93.
10. "Recent Advances in Residua Processing", NPRA 72nd Annual Meeting, April 1974.
11. "Capital Investments of the World Petroleum Industry - 1972", Chase Manhattan Bank, pp 24.

TABLE V-1
CUMULATIVE CAPITAL REQUIREMENTS TO IMPLEMENT
UNLEADED GASOLINE AND LEAD PHASEDOWN PROGRAMS
ABOVE 1973 REFERENCE LEVEL

	Cumulative Investment, M\$		
	1977	1980	1985
<u>M-1 Model: Capacity 7,500 B/D</u>			
Facility Cost	1,100	1,400	1,850
Royalty and Catalyst	60	80	100
Interest, Owner's Engineering and Startup	130	170	220
Working Capital	-	-	-
Total	1,290	1,650	2,170
<u>M-2 Model: Capacity 40,000 B/D</u>			
Facility Cost	3,580	6,600	10,450
Royalty and Catalyst	580	900	1,380
Interest, Owner's Engineering and Startup	430	790	1,250
Working Capital	240	400	640
Total	4,830	8,690	13,720
<u>C-1 Model: Capacity 105,000 B/D</u>			
Facility Cost	7,170	11,540	16,970
Royalty and Catalyst	940	950	1,470
Interest, Owner's Engineering and Startup	860	1,380	2,040
Working Capital	520	880	1,410
Total	9,490	14,750	21,890
<u>C-2 Model: Capacity 267,000 B/D</u>			
Facility Cost	14,140	21,240	38,280
Royalty and Catalyst	1,120	1,520	3,610
Interest, Owner's Engineering and Startup	1,700	2,550	4,590
Working Capital	1,270	2,140	3,420
Total	18,230	27,450	49,900
<u>W-1 California Model: Capacity 90,000 B/D</u>			
Facility Cost	5,230	9,930	16,050
Royalty and Catalyst	390	970	1,520
Interest, Owner's Engineering and Startup	630	1,190	1,930
Working Capital	460	780	1,250
Total	6,710	12,870	20,750

TABLE V-2
ADDED REFINING COSTS IMPOSED BY UNLEADED
GASOLINE AND LEAD PHASEDOWN PROGRAMS
(\$/Day)

	1977	1980	1985
<u>M-1 Model: Capacity 7,500 B/D</u>			
Incremental Gasoline Revenue @37.7¢/Gal.	-	-	-
Byproduct Revenue	350	420	530
Raw Materials	170	220	300
Operating Cost	(80)	(50)	(60)
Capital Charges	910	1,480	1,530
Total	1,350	2,070	2,300
<u>M-2 Model: Capacity 40,000 B/D</u>			
Incremental Gasoline Revenue @37.7¢/Gal.	(21,410)	(29,150)	(39,760)
Byproduct Revenue	-	-	-
Raw Materials	19,820	27,100	36,960
Operating Cost	(630)	130	210
Capital Charges	3,420	6,150	9,710
Total	1,200	4,230	7,120
<u>C-1 Model: Capacity 105,000 B/D</u>			
Incremental Gasoline Revenue @37.7¢/Gal.	(47,250)	(64,270)	(87,610)
Byproduct Revenue	(12,180)	(9,340)	(12,740)
Raw Materials	65,950	78,520	107,040
Operating Cost	(2,680)	(5,160)	(4,790)
Capital Charges	6,710	10,430	15,480
Total	10,550	10,180	17,380
<u>C-2 Model: Capacity 267,000 B/D</u>			
Incremental Gasoline Revenue @37.7¢/Gal.	(114,560)	(155,850)	(212,410)
Byproduct Revenue	(14,540)	(19,360)	(26,390)
Raw Materials	134,670	181,330	247,130
Operating Cost	(6,500)	(7,030)	(12,660)
Capital Charges	12,900	19,420	35,300
Total	11,970	18,510	30,970
<u>W-1 California Model: Capacity 90,000 B/D</u>			
Incremental Gasoline Revenue @37.7¢/Gal.	(41,850)	(56,940)	(77,620)
Byproduct Revenue	(12,010)	(24,390)	(33,250)
Raw Materials	59,540	74,720	101,860
Operating Cost	(430)	470	(1,290)
Capital Charges	4,750	9,100	14,600
Total	10,000	2,960	4,900

TABLE V-3
CUMULATIVE CAPITAL REQUIREMENTS TO IMPLEMENT
UNLEADED GASOLINE PROGRAM ABOVE 1973 REFERENCE LEVEL
(M\$)

	<u>1977</u>	<u>1980</u>	<u>1985</u>
<u>M-1 Model: Capacity 7,500 B/D</u>			
Facility Cost	490	900	1,660
Royalty and Catalyst	40	70	120
Interest, Owner's Engineering and Startup	60	110	200
Working Capital	-	-	-
Total	<u>590</u>	<u>1,080</u>	<u>1,980</u>
<u>M-2 Model: Capacity 40,000 B/D</u>			
Facility Cost	2,040	5,080	8,900
Royalty and Catalyst	530	1,020	1,620
Interest, Owner's Engineering and Startup	240	610	1,070
Working Capital	240	400	640
Total	<u>3,050</u>	<u>7,110</u>	<u>12,230</u>
<u>C-1 Model: Capacity 105,000 B/D</u>			
Facility Cost	920	5,690	14,460
Royalty and Catalyst	110	810	2,100
Interest, Owner's Engineering and Startup	110	680	1,740
Working Capital	520	880	1,410
Total	<u>1,660</u>	<u>8,060</u>	<u>19,710</u>
<u>C-2 Model: Capacity 267,000 B/D</u>			
Facility Cost	-	12,060	32,240
Royalty and Catalyst	-	1,040	4,050
Interest, Owner's Engineering and Startup	-	1,450	3,870
Working Capital	1,270	2,140	3,420
Total	<u>1,270</u>	<u>16,690</u>	<u>43,580</u>
<u>W-1 California Model: Capacity 90,000 B/D</u>			
Facility Cost	2,950	8,670	14,050
Royalty and Catalyst	350	860	1,350
Interest, Owner's Engineering and Startup	350	1,040	1,590
Working Capital	460	780	1,250
Total	<u>4,110</u>	<u>11,350</u>	<u>18,240</u>

TABLE V-4
ADDED REFINING COSTS IMPOSED BY
UNLEADED GASOLINE PROGRAM
(\$ Per Calendar Day)

	1977	1980	1985
M-1 Model: Capacity 7,500 B/D			
Incremental Gasoline Revenue @37.7¢/Gal.	-	-	-
Byproduct Revenue	140	320	400
Raw Materials	0	90	120
Operating Cost	(60)	(110)	(150)
Capital Charges	420	760	1,400
Total	500	1,060	1,770
M-2 Model: Capacity 40,000 B/D			
Incremental Gasoline Revenue @37.7¢/Gal.	(21,410)	(29,150)	(39,760)
Byproduct Revenue	-	-	-
Raw Materials	19,560	26,660	36,360
Operating Cost	30	(170)	(160)
Capital Charges	2,160	5,030	8,650
Total	340	2,370	5,090
C-1 Model: Capacity 105,000 B/D			
Incremental Gasoline Revenue @37.7¢/Gal.	(47,250)	(64,270)	(87,610)
Byproduct Revenue	(12,180)	(9,340)	(12,740)
Raw Materials	62,180	76,140	103,790
Operating Cost	(700)	(2,790)	(2,440)
Capital Charges	1,170	5,700	13,940
Total	3,220	5,440	14,940
C-2 Model: Capacity 267,000 B/D			
Incremental Gasoline Revenue @37.7¢/Gal.	(114,560)	(155,850)	(212,410)
Byproduct Revenue	(14,540)	(19,360)	(26,390)
Raw Materials	128,110	176,480	240,530
Operating Cost	(2,180)	(3,930)	(7,230)
Capital Charges	900	11,810	30,830
Total	(2,270)	9,150	25,330
W-1 California Model: Capacity 90,000 B/D			
Incremental Gasoline Revenue @37.7¢/Gal.	(41,850)	(56,940)	(77,620)
Byproduct Revenue	(11,770)	(24,200)	(32,990)
Raw Materials	54,570	73,450	100,130
Operating Cost	270	580	(370)
Capital Charges	2,910	8,030	12,970
Total	4,130	920	2,120

TABLE V-5

1973 RESIDUAL FUEL CONSUMPTION BY SULFUR LEVEL (WT.%)

(Thousand Barrels Per Year)

	<u>0-0.5</u>	<u>0.5-1.0</u>	<u>1.0-2.0</u>	<u>Over 2.0</u>	<u>Total</u>
<u>PAD I</u>					
Domestic Source	14,700	25,200	16,800	11,500	68,200
Imported	232,900	130,300	74,900	160,800	598,900
<u>PAD II</u>					
Domestic Source	2,000	35,700	26,800	15,300	79,800
Imported	1,700	2,000	1,700	800	6,200
<u>PAD III</u>					
Domestic Source	7,800	11,100	8,400	34,700	62,000
Imported	200	2,300	500	1,400	4,400
<u>PAD IV</u>					
Domestic Source	800	2,500	3,300	3,300	9,900
Imported	-	-	-	-	-
<u>PAD V</u>					
Domestic Source	71,400	8,100	47,500	7,800	134,800
Imported	9,500	-	1,500	200	11,200
<u>Total U.S.</u>					
Domestic Source	96,700	82,600	102,800	72,600	354,700
Imported	244,300	134,600	78,600	163,200	620,700
Total Residual Fuel	341,000	217,200	181,400	235,800	975,400
Crude Burned as Residual Plus Inventory Adjustments					54,800
					1,030,200

Sources:

Mineral Industry Surveys, "Availability of Heavy Fuel Oils by Sulfur Levels", U.S. Bureau of Mines, December 1973.

Mineral Industry Surveys, "Crude Petroleum, Petroleum Products and Natural Gas Liquids", U.S. Bureau of Mines, 1973 Final Summary.

TABLE V-6
ESTIMATED RESIDUAL FUEL DEMAND
THROUGH 1983 BY PAD
(MB/D)

	<u>1973</u>	<u>1977</u>	<u>1983</u>
PAD I	1,930	2,010	2,120
PAD II	250	260	270
PAD III	190	200	210
PAD IV	30	30	30
PAD V	<u>420</u>	<u>440</u>	<u>460</u>
Total	2,820	2,940	3,090

Source: Adapted from: Emergency Preparedness: Interruption of Petroleum Imports into the United States, National Petroleum Council, September 1974.

TABLE V-7
PHYSICAL PROPERTIES OF LIGHT ARABIAN
CRUDE AND ITS TBP CUTS

<u>TBP Range</u>	<u>Volume % on Crude(1)</u>	<u>°API</u>	<u>Weight % Sulfur</u>
Whole Crude	100.0	34.2	1.65
Light Ends (C ₁ - C ₄)	1.58	(2)	-(2)
Naphtha (C ₅ - 375°)	26.12	63.0	0.032
Distillate (375-650°)	27.6	39.6	0.7(3)
Fuel Oil (650°+)	44.7	17.2	2.89

- Notes: (1) Volume percent yields were applied to 200 MBD and 30 MBD cases to determine flow rates to downstream processes.
(2) Not determined for this study.
(3) In meeting the low-sulfur specifications on the fuel oil, some of this material was blended into the fuel oil stream. For purposes of those blends, it was assumed that the distillates had been desulfurized to 0.1 weight percent sulfur.

TABLE V-8
RESIDUAL FUEL DESULFURIZATION INVESTMENT ESTIMATES

Refinery Crude Feed Rate, MB/CD	200	200	30	30
HDS Unit Feed Rate, MB/CD	90	90	14	14
Sulfur Content of 650°F.+ Residuum, Wt.%	2.9	2.9	2.9	2.9
Sulfur Limit on Fuel Oil, Wt.%	0.7	0.3	0.7	0.3
<u>Battery Limits Investments, \$MM</u>				
Residual Desulfurization Unit	49	73	10	15
Hydrogen Generation	15	18	4	5
Sulfur Plant	<u>6</u>	<u>7</u>	<u>2</u>	<u>2</u>
Sub-Total	70	98	16	22
<u>Offsites, \$MM</u>				
Tankage and Tank Farm Piping	9	9	1	1
Interconnecting Piping	8	12	2	3
Sulfur Handling and Storage	6	7	2	2
Utilities Systems	6	7	2	2
Other Supporting Systems	<u>9</u>	<u>13</u>	<u>2</u>	<u>3</u>
Sub-Total	38	48	9	11
Total Investment Requirements	108	146	25	33

TABLE V-9
ANNUAL DESULFURIZATION COSTS

Refinery Crude Feed Rate, MB/CD	200	200	30	30
Sulfur Limit on Fuel Oil, Wt. %	0.7	0.3	0.7	0.3
Residual Fuel Production Meeting Sulfur Specification, MB/CD	87.2	87.5	13.1	13.1
<u>Operating Costs, \$M/Year</u>				
Labor	1,840	2,360	490	610
Plant Overhead and General & Administrative Expense	920	1,180	250	300
Maintenance Materials	2,130	2,910	490	660
Utility and Energy Costs	23,100	21,800	3,460	3,330
Operating Supplies and Miscellaneous	540	720	120	160
Sub-Total Operating Costs	28,530	28,970	4,810	5,060
<u>Capital Charges</u>	<u>27,890</u>	<u>37,440</u>	<u>6,450</u>	<u>8,520</u>
Total Annual Costs	56,420	66,410	11,260	13,580
Cost Per Barrel of Fuel Oil Meeting Sulfur Specifications, \$	1.77	2.08	2.35	2.84

APPENDIX

Table A-1

**U. S. REFINING CAPACITIES AND
WASTEWATER CHARACTERIZATION**
(as of 1-1-74)

Company - City	State	PAC	Processing Capacity, MB/50			Cracking Lube Asphalt			Wastewater Characterization*		
			Desalt.	Atmos.	Vac.	Ref.	Cracking Lube	Asphalt	Process Configuration	Refinery Type	Process Size Factor
Specialty Refiners -											
No Reforming or											
Catalytic Conversion											
Anoco - Savannah	Ge.	1	-	12.5	-	-	-	8.0	9.00	A13	1.693
Young Ref., -Douglasville	Ge.	1	-	2.5	-	-	-	1.3	7.24	A13	1.693
Anoco-Baltimore	Mo.	1	-	10.0	-	-	-	8.0	10.60	A14	2.825
Chevron-Baltimore	Mo.	1	14.0	14.0	13.8	-	-	11.0	12.27	A14	2.825
Seminole Asphalt-St. Marks	Fla.	1	5.5	5.5	2.4	-	-	2.5	7.89	A13	1.693
Valvoline/Ashland-Freedom	Pa.	1	6.5	6.5	2.0	-	-	-	4.91	A12	1.020
Pennzoil - Reno	Pa.	1	-	2.0	-	-	-	1.2	10.45	A14	2.825
Sun-Yabocoo	P.R.	1	66.0	66.0	30.0	-	-	19.5	6.30	A22	1.210
Crystal-Carson City	Mich.	2	6.5	6.5	2.8	-	-	-	2.43	A11	0.612
Wineback-Plymouth	Ill.	2	-	1.5	-	-	-	-	1.00	A11	0.612
Witter-Colmar	Ill.	2	1.1	1.1	1.0	-	-	-	2.91	A11	0.612
Gladieux-Ft. Wayne	Ind.	1	10.5	10.5	5.0	-	-	2.6	2.00	A11	0.612
Ashland-Laketon	Ind.	1	8.9	8.9	5.0	-	-	6.0	6.07	A12	0.612
Ashland-Findlay	Ohio	2	20.0	20.0	8.0	-	-	6.0	6.00	A12	1.020
Somerset-Somerset	Ky.	2	-	3.0	-	-	-	2.5	11.00	A14	2.825
Mid-America-Chanute	Kan.	2	-	3.3	1.8	-	-	-	1.55	A11	0.612
Allied Mat'ls.-Stroud	Okla.	2	5.8	5.8	2.8	-	-	1.2	6.98	A12	1.020
Tenkawa Ref.-Arnett	Okla.	2	6.5	6.5	-	-	-	1.0	2.00	A11	0.612
Berry/Crystal-Stephens	Ark.	2	2.5	3.5	1.0	-	-	1.0	5.71	A12	1.020
Cross-Sackover	Ark.	2	5.0	5.0	2.0	-	-	1.4	11.22	A14	2.825
MacMillan-Norphet	Ark.	2	4.5	4.5	2.8	-	-	1.3	6.09	A12	1.020
Vulcan Asphalt-Cordova	Ala.	2	-	3.0	-	-	-	1.8	7.75	A13	1.693
Warrior Asphalt-Holt	Ala.	2	-	3.0	-	-	-	1.7	8.85	A13	1.693
Southland-Crupp	Miss.	3	4.0	4.0	-	-	-	1.4	6.00	A12	1.020
Southland-Lumberton	Miss.	3	6.0	6.0	-	-	-	2.3	6.60	A12	1.020
Southland-Sandersville	Miss.	2	11.0	11.0	6.0	-	-	3.5	6.36	A12	1.020
Bayou State - Hosston	La.	2	3.7	3.7	2.0	-	1.5	0.5	11.16	U13	1.235
Calumet - Princeton	La.	3	4.1	4.1	2.4	-	-	1.3	9.44	A13	1.693
Kerr McGee-Cotton Valley	La.	3	8.0	8.0	-	-	-	1.7	2.00	A11	0.612
Marion-Mobile	Ala.	3	15.5	15.5	-	-	-	-	2.00	A11	0.612
Ladet-St. James	La.	3	11.0	11.0	-	-	-	-	2.00	A11	0.612
Adobe Crystal-LaBlanca	Tex.	3	5.0	5.0	-	-	-	-	2.00	A11	0.612
Eddy-Houston	Tex.	3	-	3.4	-	-	-	-	1.00	A11	0.612
Flint Chem.-San Antonio	Tex.	3	-	1.2	-	-	-	-	1.00	A11	0.612
Texaco-Port Neches	Tex.	3	29.5	49.5	27.4	-	-	9.0	4.33	A12	1.020

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Table A-1
(continued)

Company - City	State	PAC	Processing Capacity, MB/SD			Cracking Lube Asphalt			Mastewater Characterization*		
			Desalt.	Crude Oil	Var.	Ref.	Cracking Lube	Asphalt	Process Configuration	Refinery Type	Process Factor
Quintana/Howell-Corpus Christi	Tex.	3	10.5	10.5	-	-	-	-	2.00	A11	0.612
Pride-Abilene	Tex.	3	14.7	14.7	-	-	-	-	2.00	A11	0.612
Tesoro-Carrizo Springs	Tex.	3	13.5	13.5	-	-	-	-	2.00	A11	0.612
Tex. Asphalt-Ft. Worth	Tex.	3	-	3.5	-	-	-	-	1.00	A11	0.612
Three Rivers-Three Rivers	Tex.	3	-	1.6	0.8	-	0.8	0.1	8.75	A13	1.693
Caribou 4 Corners - Kirtland	NM	3	-	2.2	-	-	-	-	1.00	A11	0.612
Thriftyway-Bloomfield	NM	3	-	2.2	-	-	-	-	1.00	A11	0.612
Jet Fuel Ref.-Mosby	Mont.	4	-	1.1	-	-	-	-	1.00	A11	0.612
Tesoro-Wolf Pt.	Mont.	4	-	2.7	-	-	-	-	1.00	A11	0.612
Mountaineer-LaBarge	Wyo.	4	-	0.5	-	-	-	-	1.00	A11	0.612
Southwestern-LaBarge	Wyo.	4	-	0.3	-	-	-	-	1.00	A11	0.612
Sound Ref.-Tacoma	Wash.	5	4.7	4.7	4.5	-	1.9	2.6	14.85	A15	4.172
Socal-Richmond Beach	Wash.	5	-	5.0	5.0	-	-	4.0	11.60	A14	2.825
Socal-Portland	Ore.	5	-	15.0	15.0	-	-	8.6	8.88	A13	1.693
Ariz. Fuels - Fredonia	Ariz.	5	10.0	10.0	4.0	-	-	-	2.40	A11	0.612
Champion-Wilmington	Cal.	5	-	30.0	18.0	-	10.0	-	3.60	B12	0.721
Douglas-Santa Maria	Cal.	5	8.5	8.5	7.5	-	-	5.8	11.07	A14	2.825
Edington-Long Beach	Cal.	5	29.5	29.5	19.0	-	-	7.5	5.69	A12	1.020
Edington-Danard	Cal.	5	-	2.5	-	-	-	-	1.00	A11	0.612
GB/Witco-Oildale	Cal.	5	11.0	11.0	9.5	-	4.0	3.2	11.08	A14	2.825
Golden Eagle-Carson	Cal.	5	13.0	13.0	-	-	-	-	2.00	A11	0.612
Lunday-Thagard-South Gate	Cal.	5	5.2	5.2	3.0	-	-	1.6	6.27	A12	1.020
MacMillan-Signal Hill	Cal.	5	10.0	10.0	-	-	-	-	2.00	A11	0.612
Newhall Ref.-Newhall	Cal.	5	-	8.0	5.0	-	-	3.0	6.13	A12	1.020
San Joaquin-Bidale	Cal.	5	18.0	18.0	7.0	-	-	3.4	4.66	A12	1.020
Tenneco-Bakersfield	Cal.	5	-	1.3	-	-	-	-	1.00	A11	0.612
W. Coast Oil-Bakersfield	Cal.	5	16.8	16.8	-	-	2.0	4.0	5.57	B13	1.006
Hawaiian Indep.-Barber's Point	Haw.	5	31.6	31.6	-	-	-	-	2.00	A11	0.612
Arco-Ho. Slope	Alk.	5	-	5.1	-	-	-	-	1.00	A11	0.612
BP-Ho. Slope	Alk.	5	-	1.3	-	-	-	-	1.00	A11	0.612
Socal-Kenai	Alk.	5	23.2	23.2	-	-	-	0.3	2.16	A11	0.612
Tesoro-Kenai	Alk.	5	39.5	39.5	-	-	-	-	2.00	A11	0.612
Conoco-Guam	Guam	5	30.0	30.0	-	-	-	-	2.00	A11	0.612
Subtotal 66 Refineries			552.0	699.2	211.5	-	13.5	35.7	111.6		

Gasoline Refiners
under 100 MB/SD Capacity

Bratford/Witco - Bradford
Pennco - Rouseville

11.50
13.07

2.825
4.172

Table A-1
(continued)

Company - City	State	PAU	Crude Oil			Processing Capacity, MB/SD			Mastewater Characterization*			
			Unsalt	Atmos	Vac.	Cat. Ref.	Cracking	Lube	Asphalt	Process Configuration	Refinery Type	Process Factor
Quaker St. - Eminton	Pa.	1	3.5	2.5	1.7	1.3	1.4	3.9	-	19.37	B15	1.664
Quaker St. - Farmers Valley	Pa.	1	6.8	6.8	2.8	1.9	1.4	6.5	-	16.07	B15	1.664
Pennzoil - Falling Rock	W. Va	1	5.5	5.5	2.5	2.0	-	3.4	-	10.49	A14	2.825
Quaker St. - Newell	W. Va	1	10.0	10.0	4.0	2.9	-	10.9	-	16.57	A15	4.172
Quaker St. - St. Mary's	W. Va	1	5.0	5.0	2.2	1.3	-	4.6	-	14.40	A15	4.172
Ind. Farm Bu. Coop. - Mt. Vernon	Kan.	2	15.2	15.2	6.0	3.0	5.8	-	-	4.68	B12	0.721
No. Amer. Ref. - Shallow Water	Ind.	2	5.3	5.3	2.5	-	4.5	-	-	7.57	B14	1.424
Bay Ref./Low - Bay City	Mich.	2	17.3	17.3	-	-	6.3	-	-	4.78	B12	0.721
Lakeside Ref. - Kalamazoo	Mich.	2	6.3	6.3	-	2.0	-	-	-	2.00	A11	0.612
USTEOLA Ref. - W. Branch	Mich.	2	9.5	9.5	-	1.4	-	-	-	2.00	A11	0.612
CRA - Sontestuff	Nebr.	2	5.5	5.5	2.0	1.0	7.6	-	-	3.32	B12	0.516
Westland - Williston	Neb.	2	5.0	5.0	-	2.0	1.1	-	-	7.25	B13	1.006
Apco - Cyril	Okla.	2	12.3	12.3	5.0	1.0	7.3	-	1.3	6.60	B13	1.006
Midland Coop. - Cushing	Okla.	2	19.5	19.5	7.0	4.5	14.0	-	-	2.00	A11	0.612
Hunt Oil - Tuscaloosa	Ala.	2	15.0	15.0	8.7	1.4	-	-	5.2	2.00	A11	0.612
Canal Ref. - Church Point	La.	2	2.8	2.8	-	1.5	-	-	-	1.00	A11	0.612
Evangeline - Jennings	La.	2	4.3	4.3	-	0.6	-	-	-	1.00	A11	0.612
Famariss - Monument	N.M.	2	-	5.3	-	0.7	-	-	-	1.00	A11	0.612
Plateau - Bloomfield	N.M.	2	-	5.2	-	2.3	-	-	-	2.00	A11	0.612
Howell Hydrom. - San Antonio	N.M.	2	-	5.3	-	0.2	-	-	-	1.00	A11	0.612
Langview/Crystal - Langview	Tex.	3	3.3	3.3	-	0.2	-	-	-	2.00	A11	0.612
Exxon - El Paso	Tex.	3	17.8	17.8	-	1.5	-	-	-	1.00	A11	0.612
United Ref./Albion - Winnie	Tex.	3	10.0	10.0	-	3.5	14.8	-	-	6.85	B13	1.006
Winston - Ft. Worth	Tex.	3	15.5	15.5	3.5	6.2	3.0	-	-	2.82	B11	0.516
2. Western (Gilsonte) Grand Junction	Colo.	4	8.5	8.5	-	1.1	6.0	-	-	4.58	B12	0.721
Freco - Commerce City	Colo.	4	12.4	12.4	3.5	3.6	8.5	-	-	8.00	B14	1.424
Big West - Kevin	Mont.	4	5.3	5.3	2.2	1.0	1.5	-	-	6.92	B13	1.006
Phillips - Great Falls	Mont.	4	6.6	6.6	2.1	0.8	3.0	-	0.3	4.11	B12	0.721
4. Stedco - Gut Bank	Mont.	4	5.0	5.0	-	1.0	2.2	-	0.8	6.93	B13	1.006
Arizona Fuels - Roosevelt	Mont.	4	11.0	11.0	-	1.0	2.2	-	-	4.64	B12	0.721
Caribou Four Corners - Woods Cross	Utah	4	5.0	5.0	1.0	2.0	6.0	-	-	5.27	B12	0.721
Husky - No. Salt Lake	Utah	4	12.0	12.0	3.8	1.0	1.0	-	-	3.40	B11	0.516
Husky - Cody	Wyo.	4	11.8	11.8	6.5	1.2	4.2	-	-	5.77	B13	1.006
Sage Creek - Cowley	Wyo.	4	-	1.2	-	0.5	-	-	4.0	9.17	B14	1.424
Tasoro - Newcastle	Wyo.	4	11.0	11.0	-	-	8.0	-	-	1.00	A1	0.612
Beacon - Hanford	Cal.	5	12.1	12.1	-	1.7	3.3	-	-	6.36	B13	1.006
Fletcher - Carson	Cal.	5	16.2	16.2	-	4.5	-	-	-	2.64	B11	0.516
Kern Co. - Bakersfield	Cal.	5	13.6	13.6	-	2.5	6.2	-	-	2.00	A11	0.612
Sunland - Bakersfield	Cal.	5	9.0	9.0	-	1.0	-	-	-	4.74	B13	0.721
5. Oil & Ref. - Tacoma	Wash.	5	16.8	16.8	3.2	3.0	-	-	3.0	2.00	A11	0.612
Suntotal 42 Refineries			354.6	395.9	72.0	74.7	135.3	43.6	14.6	4.33		1.020

Table A-1
(continued)

Company - City	State	PAO	Crude Oil			Processing Capacity, MB/SD			Cracking	Lube	Asphalt	Wastewater Characterization*		
			Desalt.	Atmos.	Vac.	Cat. Ref.		Process Configuration				Refinery Type	Process Factor	
Gasoline Refiners, 20 to 70 MB/SD Capacity, Excluding California														
Ashland - Tonawanda	N.Y.	1	67.0	67.0	25.0	11.5	26.0	-	-	-	10.0	6.49	C22	0.792
Mobil - Buffalo	N.Y.	1	44.0	44.0	18.0	11.2	25.0	-	-	-	7.5	7.86	B24	1.600
United - Warren	Pa.	1	38.0	38.0	8.0	10.0	10.2	-	-	-	4.0	5.08	B22	0.810
Carib.Gulf Ref. - Bayamon	P.R.	1	40.0	40.0	9.0	5.5	8.5	-	-	-	-	3.50	B22	0.810
Amoco - Yorktown	Va.	1	55.8	55.8	28.0	8.0	44.5	-	-	-	-	7.29	C23	1.105
Clark - Hartford	Ill.	2	38.0	38.0	15.0	9.2	40.6	-	-	-	-	8.71	B24	1.600
Mobil - E. Chicago	Ind.	2	50.8	50.8	8.0	11.0	30.0	-	-	-	-	5.70	B23	1.130
Rock Island - Indianapolis	Ind.	2	31.0	31.0	14.0	8.0	19.5	-	-	-	3.0	7.39	B13	1.006
Fine - El Dorado	Kan.	2	26.3	26.3	9.0	4.0	11.5	-	-	-	2.0	5.88	B13	1.006
APCO - Arkansas City	Kan.	2	26.0	26.0	5.0	6.3	15.0	-	-	-	1.4	6.30	B13	1.006
CRA - Coffeyville	Kan.	2	36.0	36.0	12.5	8.6	22.7	-	5.6	-	-	8.15	D12	0.873
CRA - Phillipsburg	Kan.	2	21.0	21.0	7.5	3.5	7.4	-	-	-	2.0	5.61	B13	1.006
Derby - Wichita	Kan.	2	27.0	27.0	8.8	5.0	16.4	-	-	-	-	5.97	B13	1.006
Mobil - Augusta	Kan.	2	-	52.0	17.7	10.0	27.6	-	-	-	8.0	6.37	B23	1.130
NCRA - McPherson	Kan.	2	57.0	57.0	-	7.0	38.0	-	-	-	-	6.00	B23	1.130
Ashland - Louisville	Ky.	2	26.0	26.0	10.0	3.0	11.7	-	-	-	3.5	6.70	B13	1.006
Marathon - Detroit	Mich.	2	64.0	64.0	25.0	16.0	25.4	-	-	-	8.7	6.40	C24	0.752
Total Leonard - Alma	Mich.	2	43.0	43.0	17.0	13.4	14.3	-	-	-	3.0	5.23	B22	0.810
Conoco - Wrenshall	Minn.	2	24.0	24.0	-	3.6	9.5	-	-	-	-	4.38	B12	0.721
No. Western/Ashland - St. Paul Park	Minn.	2	64.0	64.0	38.0	10.0	21.5	-	-	-	22.0	8.72	B24	1.600
Amoco - Mandan	N.D.	2	50.5	50.5	-	8.2	34.0	-	-	-	-	6.04	B23	1.130
Ashland - Canton	Okla.	2	62.0	62.0	24.0	11.0	28.6	-	-	-	10.0	7.09	B23	1.130
Gulf - Cleve	Okla.	2	43.5	43.5	13.0	10.0	27.0	-	-	-	2.9	6.82	B23	1.130
Gulf - Toledo	Okla.	2	51.0	51.0	12.5	11.0	22.0	-	-	-	-	5.30	B22	0.810
Champion - Enid	Okla.	2	52.0	52.0	10.0	15.0	25.2	5.7	-	-	1.4	7.00	D11	0.625
Kerr-McGee - Wynnewood	Okla.	2	34.0	34.0	10.0	7.5	18.0	-	-	-	3.5	6.71	B13	1.006
OKC - Okmulgee	Okla.	2	22.6	22.6	3.2	-	10.0	-	-	-	1.4	5.54	B13	1.006
Sun - Duncan	Okla.	2	50.0	50.0	17.0	7.8	47.5	-	-	-	-	8.04	B24	1.600
Texaco - W. Tulsa	Okla.	2	52.6	52.6	14.5	8.0	32.7	-	-	-	5.0	6.01	B13	1.130
Vickers - Ardmore	Okla.	2	32.0	32.0	11.0	6.5	15.5	-	-	-	-	7.13	B13	1.006
Delta - Memphis	Tenn.	2	30.0	30.0	-	-	12.0	-	-	-	3.0	5.60	B13	1.006
Murphy - Superior	Wis.	2	38.0	38.0	15.5	8.2	10.7	-	-	-	12.0	7.59	B24	1.600
Lion - El Dorado	Ark.	3	45.0	45.0	18.0	5.5	25.2	0.8	-	-	6.0	2.02	D11	0.625
Atlas Proc. - Shreveport	La.	3	30.5	30.5	0.6	10.0	-	-	-	-	-	2.00	A11	0.612
Good Hope - Good Hope	La.	3	31.0	31.0	-	3.5	-	-	-	-	-	2.00	A11	0.612
Gulf - Venice	La.	3	29.1	29.1	-	18.0	11.5	-	-	-	-	4.37	E12	0.721

Table A-1
(continued)

Company - City	State	PAD	Crude Oil			Processing Capacity, MB/SD			Wastewater Characterization*				
			Desalt.	Atmos.	Vac.	Cat. Ref.	Cracking	Lube	Asphalt	Process Configuration	Refinery Type	Process Factor	
Amerada-Hess - Purvis	Miss.	3	30.0	30.0	-	5.7	28.6	-	-	-	7.72	B14	1.424
Navajo - Artesia	NM	3	22.0	22.0	4.5	1.9	8.0	-	-	1.4	5.15	B12	0.721
Shell - Ciniza	NM	3	21.0	21.0	8.0	7.0	10.5	-	-	0.8	5.84	B13	1.006
Fina - Mt. Pleasant	Tex.	3	27.4	27.4	15.0	3.0	11.8	-	-	8.0	8.64	B14	1.424
Champion - Corpus Ch.	Tex.	3	-	63.0	9.2	26.3	10.1	-	-	-	2.11	B21	0.580
Charter - Houston	Tex.	3	66.0	66.0	22.0	13.5	39.0	-	-	4.0	6.61	B23	1.130
Cosden - Big Spring	Tex.	3	68.4	68.4	25.0	20.0	35.0	-	-	8.0	6.84	C23	1.105
Diamond Shamrock-Sunray	Tex.	3	49.0	49.0	14.5	14.0	29.5	-	-	2.5	6.52	B23	1.130
LaGloria - Tyler	Tex.	3	29.0	29.0	-	9.5	30.0	-	-	-	8.21	B14	1.424
Marathon - Texas City	Tex.	3	63.0	63.0	20.0	8.0	33.0	-	-	-	5.46	C22	0.792
Shell - Odessa	Tex.	3	34.0	34.0	10.0	9.7	15.5	-	-	-	5.03	B12	0.721
Sun - Corpus Ch.	Tex.	3	60.0	60.0	10.0	24.0	34.2	-	-	-	5.59	C22	0.792
Texaco - Amarillo	Tex.	3	21.1	21.1	-	5.0	13.3	-	-	-	5.78	B13	1.006
Tex. City Ref.-Tex. City	Tex.	3	63.0	63.0	14.5	11.0	28.0	-	-	-	4.90	B22	0.810
Conoco - Commerce City	Colo.	4	26.0	31.0	7.0	6.5	14.5	-	-	3.3	6.15	B13	1.006
Amoco-Salt Lake City	Utah	4	41.1	41.1	-	5.5	22.0	-	-	2.5	5.94	B23	1.130
Chevron - Salt Lake City	Utah	4	47.4	47.4	27.0	5.5	25.0	-	-	-	5.73	B23	1.130
Phillips - Woods Cross	Utah	4	24.2	24.2	3.0	4.5	10.5	-	-	2.2	5.82	B13	1.006
Amoco - Casper	Wyo.	4	-	45.3	13.5	5.2	11.0	5.7	-	1.6	4.81	D11	0.625
Husky - Cheyenne	Wyo.	4	24.6	24.6	14.0	6.2	12.5	-	-	3.0	7.08	B13	1.006
Little Amer. - Casper	Wyo.	4	23.0	23.0	5.8	3.8	10.5	-	-	2.0	6.03	B13	1.006
Pasco - Sinclair	Wyo.	4	42.0	42.0	14.2	9.7	12.8	-	-	2.3	4.82	B22	0.810
Texaco - Casper	Wyo.	4	22.1	22.1	10.5	4.5	14.6	-	-	1.5	7.25	B13	1.006
Genex - Laurel	Mont.	4	44.0	44.0	15.4	6.8	18.0	-	-	-	4.80	B22	0.810
Conoco - Billings	Mont.	4	38.0	56.0	12.2	13.0	21.0	-	-	3.5	4.90	B22	0.810
Exxon - Billings	Mont.	4	46.0	46.0	18.0	14.5	44.1	-	-	13.0	11.53	B25	1.870
Texaco - Anacortes	Wash.	5	66.3	66.3	23.1	8.0	36.1	-	-	-	5.62	B23	1.130
Socal - Barbers Pt.	Haw.	5	42.1	42.1	15.0	-	23.0	-	-	1.3	6.00	B23	1.130
Subtotal 64 Refineries			2,473.4	2,656.7	764.8	547.3	1,346.7	17.8	-	183.2			

Gasoline Refiners,
70 to 150 MB/SD Capacity,
Excluding California

BP - Marcus Hook	Pa.	1	105.0	105.0	60.0	22.0	53.9	-	-	-	5.65	B33	1.288
Am. Hess. - Fort Reading	NJ	1	75.0	75.0	30.0	6.5	45.0	-	-	-	6.00	B33	1.288
Chevron - Perth Amboy	NJ	1	92.0	92.0	50.0	14.0	38.0	-	-	25.0	8.28	B33	1.824
Mobil - Paulsboro	NJ	1	100.5	100.5	62.6	23.5	56.2	30.8	-	-	9.96	D21	0.996
Texaco - Westville	NJ	1	92.6	92.6	31.1	14.5	72.2	-	-	-	7.01	C23	1.105
Amoco - Wood River	Ill.	2	112.6	112.6	40.0	12.3	42.0	-	-	10.8	5.74	C32	0.946

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Table A-1
(continued)

Company - City	State	PAD	Crude Oil			Processing Capacity, MB/SD		Cracking		Lube		Asphalt		Wastewater Characterization*	
			Desalt.	Atmos.	Vac.	Cat. Ref.	Cracking	Ref.	Lube	Asphalt	Process Configuration	Refinery Type	Process Factor		
Clark - Blue Island	Ill.	2	70.0	70.0	27.0	30.5	36.0	-	-	-	4.5	-	6.24	C22	0.792
Texaco - Lawrenceville	Ill.	2	88.4	88.4	25.3	26.7	54.8	-	-	-	3.0	-	6.41	B33	1.288
Texaco - Lockport	Ill.	2	75.8	75.8	14.7	21.1	73.3	-	-	-	-	-	8.00	B34	1.824
Phillips - Kansas City	Kan.	2	89.5	89.5	15.0	16.0	48.0	-	14.4	-	3.0	-	7.88	E12	0.690
Skelly - El Dorado	Kan.	2	75.0	75.0	23.0	21.5	57.8	-	-	-	-	-	6.93	C23	1.105
Arco - E. Chicago	Ind.	2	140.0	140.0	70.0	20.0	50.0	-	-	-	10.4	-	5.53	B43	1.480
Ashland - Catlettsburg	Ky.	2	138.0	138.0	55.0	22.5	59.0	-	-	-	10.0	-	5.83	C32	0.946
Koch - Pine Bend	Minn.	2	110.0	110.0	40.0	16.5	65.6	-	-	-	20.0	-	8.12	B44	2.096
Amoco - Sugar Creek	Mo.	2	110.5	110.5	40.0	14.0	61.0	-	-	-	6.5	-	6.38	B43	1.480
Sohio - Toledo	Oh.	2	125.0	125.0	43.0	47.7	120.3	-	-	-	7.0	-	8.79	B44	2.096
Sun - Toledo	Oh.	2	130.0	130.0	22.0	41.0	83.5	-	-	-	-	-	6.02	C32	0.946
Conoco - Ponca City	Okla.	2	120.0	120.0	34.5	31.3	90.0	-	7.7	-	3.0	-	7.92	D31	0.818
Sun - Tulsa	Okla.	2	90.0	90.0	31.5	30.0	39.6	-	37.4	-	4.2	-	10.95	D23	1.409
Conoco - Westlake	La.	3	85.0	85.0	14.5	18.5	54.0	-	-	-	-	-	5.91	C22	0.792
Murphy - Meroux	La.	3	95.4	95.4	14.5	18.0	11.0	-	-	-	-	-	2.84	B31	0.661
Tenneco - Chalmette	La.	3	97.0	97.0	23.0	35.0	55.6	-	-	-	-	-	5.68	B33	1.288
Texaco - Convent	La.	3	147.4	147.4	36.8	33.4	114.4	-	-	-	-	-	6.91	B43	1.480
Chevron - El Paso	Tex.	3	74.7	74.7	24.6	25.0	30.0	-	-	-	5.0	-	5.54	B23	1.130
Coastal States - Corpus Ch.	Tex.	3	135.0	135.0	33.0	35.0	31.3	-	-	-	0.5	-	3.68	C31	0.697
Crown Central - Houston	Tex.	3	103.0	103.0	38.0	22.0	61.5	-	-	-	-	-	5.95	B33	1.288
Fina - Port Arthur	Tex.	3	88.4	88.4	28.0	12.5	38.0	-	-	-	-	-	4.90	B32	0.923
Phillips - Borger	Tex.	3	100.0	100.0	-	26.0	70.0	-	-	-	-	-	6.20	C32	0.946
Phillips - Sweeney	Tex.	3	89.5	89.5	17.0	32.0	35.0	-	-	-	-	-	4.54	C21	0.583
So' Western-Corpus Ch.	Tex.	3	150.0	150.0	24.0	15.0	12.0	-	-	-	-	-	2.64	B51	0.818
Union - Nederland	Tex.	3	122.1	122.1	44.0	35.0	40.7	-	13.3	-	5.4	-	6.31	E11	0.538
Arco - Ferndale	Wash.	5	100.0	100.0	55.0	35.0	64.0	-	-	-	-	-	6.39	B33	1.288
Mobil - Ferndale	Wash.	5	74.5	74.5	7.0	10.0	34.5	-	-	-	-	-	4.87	B22	0.810
Shell - Anacortes	Wash.	5	94.0	94.0	33.0	20.0	53.0	-	-	-	-	-	5.73	B33	1.288
Subtotal 34 Refineries			3,495.9	3,495.9	1,100.6	804.0	1,851.2		103.6		118.3				

Gasoline Refiners
Over 150 MB/SD Capacity,
Excluding California

Getty - Delaware City	Del.	1	150.0	150.0	90.7	42.0	138.0	-	-	-	-	-	8.12	C45	1.435
Exxon - Linden	NJ	1	286.0	286.0	143.0	42.0	142.2	-	-	-	46.0	-	7.41	C43	1.435
Arco - Philadelphia	Pa.	1	195.0	195.0	57.0	60.0	30.0	-	-	-	19.5	-	4.42	B52	1.142
Gulf - Philadelphia	Pa.	1	174.0	174.0	65.0	52.0	80.5	-	-	-	-	-	5.15	B52	1.142

Table A-1
(continued)

Company - City	State	PAD	Processing Capacity, MB/SD			Crude Oil			Cat. Ref.	Cracking			Lube	Asphalt	Wastewater Characterization*		
			Desalt.	Atmos.	Vac.	Desalt.	Atmos.	Vac.		Cracking	Cracking	Cracking			Process Configuration	Refinery Type	Process Factor
Sun - Marcus Hook	Pa.	1	180.0	180.0	48.0	180.0	180.0	48.0	45.0	97.0	97.0	97.0	45.6	12.0	9.59	E23	1.157
Commonwealth - Penuelas	P.R.	1	185.0	185.0	92.5	185.0	185.0	92.5	70.0	74.0	74.0	74.0	-	1.0	4.96	C42	1.028
Amerada - Hess - St. Croix	V.I.	1	621.1	621.1	20.0	621.1	621.1	20.0	130.0	-	-	-	-	-	2.03	A41	0.942
Marathon - Robinson	Ill.	2	205.0	205.0	62.0	205.0	205.0	62.0	47.3	88.3	88.3	88.3	-	-	4.89	B52	1.142
Mobil - Joliet	Ill.	2	186.0	186.0	82.0	186.0	186.0	82.0	46.2	94.0	94.0	94.0	-	-	5.47	B52	1.142
Shell - Wood River	Ill.	2	268.0	268.0	91.5	268.0	268.0	91.5	87.0	152.5	152.5	152.5	22.4	22.5	7.85	D51	1.047
Union - Lewmont	Ill.	2	160.0	160.0	55.0	160.0	160.0	55.0	32.0	79.5	79.5	79.5	-	-	5.48	B52	1.142
Amoco - Whiting	Ind.	2	331.6	331.6	140.0	331.6	331.6	140.0	56.0	160.5	160.5	160.5	41.1	31.0	8.06	D52	1.464
Sohio - Lima	Oh.	2	175.0	175.0	51.0	175.0	175.0	51.0	50.0	80.5	80.5	80.5	9.8	-	5.78	D41	0.959
Cities Ser. - Lake Charles	La.	3	282.1	282.1	60.0	282.1	282.1	60.0	46.0	173.0	173.0	173.0	29.8	-	7.27	D51	1.047
Exxon - Baton Rouge	La.	3	460.0	460.0	165.0	460.0	460.0	165.0	99.5	274.0	274.0	274.0	88.4	28.9	9.18	E33	1.326
Gulf - Belle Chasse	La.	3	186.0	186.0	55.0	186.0	186.0	55.0	37.5	117.4	117.4	117.4	-	-	6.08	B53	1.593
Shell - Norco	La.	3	250.0	250.0	90.0	250.0	250.0	90.0	41.5	143.0	143.0	143.0	-	6.0	6.08	B53	1.593
Chevron - Pascagoula	Miss.	3	252.6	252.6	148.0	252.6	252.6	148.0	65.0	117.0	117.0	117.0	-	-	5.36	C42	1.028
Amoco - Texas City	Tex.	3	350.5	350.5	131.0	350.5	350.5	131.0	129.0	245.5	245.5	245.5	-	5.3	6.76	C43	1.435
Arco - Houston	Tex.	3	233.5	233.5	70.0	233.5	233.5	70.0	100.0	105.5	105.5	105.5	19.4	-	6.09	E31	0.796
Exxon - Baytown	Tex.	3	420.0	420.0	180.0	420.0	420.0	180.0	88.0	165.0	165.0	165.0	120.2	12.0	8.85	E32	1.020
Gulf - Port Arthur	Tex.	3	319.0	319.0	147.4	319.0	319.0	147.4	65.0	171.0	171.0	171.0	46.1	-	7.56	E32	1.020
Mobil - Beaumont	Tex.	3	335.0	335.0	103.0	335.0	335.0	103.0	94.0	185.5	185.5	185.5	31.4	0.1	6.85	D51	1.047
Shell - Deer Park	Tex.	3	293.0	293.0	106.4	293.0	293.0	106.4	77.0	201.0	201.0	201.0	26.0	3.8	7.79	D51	1.047
Texaco - Port Arthur	Tex.	3	427.4	427.4	149.5	427.4	427.4	149.5	66.6	268.3	268.3	268.3	52.6	-	7.72	D51	1.047
Subtotal 25 Refineries			6,925.8	6,925.8	2,403.0	6,925.8	6,925.8	2,403.0	1,668.6	3,383.2	3,383.2	3,383.2	532.8	190.1			
California - Gasoline Refiners Over 20 MB/SD Capacity																	
Mohawk - Bakersfield	Cal.	5	-	22.8	-	-	22.8	-	2.6	-	-	-	-	-	1.00	A11	0.612
Socal - Bakersfield	Cal.	5	-	27.4	-	-	27.4	-	5.4	-	-	-	-	1.1	1.48	A11	0.612
Tosco Petro - Bakersfield	Cal.	5	-	27.0	17.0	-	27.0	17.0	14.5	32.3	-	-	-	-	8.81	B14	1.424
Arco - Carson	Cal.	5	-	173.0	93.0	-	173.0	93.0	34.0	169.2	-	-	-	-	7.41	C43	1.435
Douglas - Paramount	Cal.	5	36.0	36.0	21.0	36.0	36.0	21.0	6.4	-	-	-	-	14.0	7.25	A*3	1.693
Exxon - Benecia	Cal.	5	95.0	95.0	53.0	95.0	95.0	53.0	24.0	100.6	-	-	-	-	8.91	B31	1.824
Gulf - Santa Fe Springs	Cal.	5	53.8	53.8	25.0	53.8	53.8	25.0	19.0	38.6	-	-	-	4.0	7.66	B24	1.600
Mobil - Torrance	Cal.	5	100.0	100.0	95.0	100.0	100.0	95.0	36.0	136.6	-	-	-	-	8.80	B44	2.096
Phillips - Avon	Cal.	5	94.7	115.8	74.5	94.7	115.8	74.5	32.5	125.1	1.7	-	-	-	9.28	D32	1.144
Powerline - Santa Fe Springs	Cal.	5	30.0	30.0	15.0	30.0	30.0	15.0	6.3	12.0	-	-	-	5.0	6.90	B13	1.006
Sequoia - Hercules	Cal.	5	28.3	28.3	5.9	28.3	28.3	5.9	15.8	2.9	-	-	-	-	2.82	B11	0.516
Shell - Martinez	Cal.	5	85.0	103.0	55.3	85.0	103.0	55.3	25.0	105.0	13.1	10.4	-	-	11.34	E13	0.897

Table A-1
(continued)

Company - City	State	PAD	Crude Oil			Processing Capacity, MB/SD			Wastewater Characterization*		
			Desalt.	Atmos.	Vac.	Cat.	Ref.	Cracking	Process Configuration	Refinery Type	Process Size Factor
Shell - Wilmington	Cal.	5	101.0	101.0	60.0	21.0	70.0	-	6.75	D21	0.713
Socal - El Segundo	Cal.	5	126.3	242.1	103.0	60.0	157.5	-	6.26	C42	1.028
Socal - Richmond	Cal.	5	200.0	200.0	150.0	70.5	122.0	85.9	12.65	E23	1.157
Texaco - Wilmington	Cal.	5	23.2	78.9	-	38.9	116.0	-	10.12	B35	2.132
Union - Los Angeles	Cal.	5	86.0	111.0	83.0	29.0	93.0	-	8.63	B44	2.096
Union - San Francisco	Cal.	5	115.0	115.0	38.5	26.0	72.5	23.2	9.39	D32	1.144
Subtotal 18 Refineries			1,174.3	1,690.1	889.2	466.9	1,353.3	123.9			
Total 251 Refineries			14,976.0	15,863.6	5,441.1	3,561.5	8,083.2	856.8			

Sources:

- (1) Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category, U. S. Environmental Protection Agency, April, 1974 (EPA-440/1-74-014-a).
- (2) "Refining Capacity Registers Largest 'Nickel and Dime' Jump in History", The Oil & Gas Journal, April 1, 1974.
- (3) "Lube Capacity in U. S. and Canada", Hydrocarbon Processing, June, 1973, p. 113.
- (4) International Petroleum Encyclopedia - 1974, Petroleum Publishing Company, Tulsa, Oklahoma. Copyright, 1974.

*Process configuration is calculated using capacity data and EPA's formula in Reference 4. Given a configuration and refinery capacity, one can derive refinery type, process and size factors from Table II-4 in Section III. These characterization factors are required to determine refinery-specific guideline pollutant discharge levels.

TABLE A-2
DOMESTIC PETROLEUM DEMAND FORECAST

	Total Petroleum Demand, MBD				
	<u>Preliminary 1974 Data</u>	<u>1978</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Motor Gasoline	6,560	7,531	7,928	8,414	8,448
Aviation Gasoline	42	48	51	56	58
Naphtha Jet	200	200	200	200	200
Kerosene Jet	780	1,010	1,135	1,519	1,939
Kerosene	160	173	175	179	183
Distillate Fuel	2,900	3,369	3,442	3,615	3,661
Residual Fuel	2,665	3,027	3,094	3,093	3,211
LPG	920	1,099	1,099	1,203	1,203
Petrochemical Feedstock	1,008	1,149	1,224	1,559	1,818
Lube and Wax	177	189	195	211	228
Coke	237	260	272	306	345
Asphalt and Road Oil	514	583	621	727	851
Still Gas	450	503	523	566	597
Other	<u>122</u>	<u>132</u>	<u>137</u>	<u>151</u>	<u>167</u>
Total	16,735	19,273	20,096	21,799	22,909

Source:

Preliminary 1974 Data - Oil & Gas Journal, January 27, 1975, pp 106.
 1978 through 1990 Data - "Forecast of Domestic Refining Industry Capacity Through 1985", Turner, Mason & Solomon, March 18, 1975, an adaptation of Emergency Preparedness: Interruption of Petroleum Imports into the United States, National Petroleum Council, September 1974.

TABLE A-3
DOMESTIC PETROLEUM REFINING CAPACITY REQUIREMENTS

Basis: Product imports to be held constant at preliminary 1974 levels.

	1974 Net Imports(1)	1974 Other Supply(2)	Domestic Refinery Demand, MB/CD				
			1974	1978	1980	1985	1990
Motor Gasoline	191	3	6,366	7,337	7,734	8,220	8,254
Aviation Gasoline	-	-	42	48	51	56	58
Naphtha Jet	30	-	170	170	170	170	170
Kerosene Jet	160	-	620	850	975	1,359	1,779
Kerosene	3	1	156	169	171	175	179
Distillate Fuel	252	3	2,645	3,114	3,187	3,360	3,406
Residual Fuel	1,664	13	988	1,350	1,417	1,416	1,534
LPG	95	574	251	430	430	534	534
Petrochemical Feedstock	(5)	330	683	824	899	1,234	1,493
Lube and Wax	(35)	-	212	224	230	246	263
Coke	(115)	-	352	375	387	421	460
Asphalt and Road Oil	33	-	481	550	588	694	818
Still Gas	-	-	450	503	523	566	597
Other	34	2	86	96	101	115	131
Total	2,307	926	13,502	16,040	16,863	18,566	19,676
NG Liquids & Other HC			(770)	(750)	(750)	(750)	(750)
Processing Gain			(475)	(560)	(590)	(650)	(689)
Crude Run			12,257	14,730	15,523	17,166	18,237
Indicated Capacity Re- quirement (@90% Utilization)			13.6	16.4	17.2	19.1	20.3

Notes: (1) Oil & Gas Journal, January 27, 1975, pp. 114.

(2) January-October 1974 Average from Mineral Industry Survey - Petroleum State-
ment, Monthly, U.S. Department of the Interior - Bureau of Mines, October
1974.

TABLE A-4

SCHEDULED REFINERY EXPANSION PROJECTS

		(MB/CD)					Total U.S.A.
	Type*	PAD I	PAD II	PAD III	PAD IV	PAD V	
Capacity 1/1/74		1,674	3,889	5,933	506	2,248	14,250
Capacity 1/1/75		1,677	4,013	6,256	532	2,388	14,866
Socal - Perth Amboy, N.J.	E	80					
Exxon - Bayway, N.J.	E	30					
Bell - Ardmore, Okla.	E		30				
Kerr-McGee - Wynnewood, Okla.	E		35				
Clark - Hartford, Ill.	E		45				
Conoco - Ponca City, Okla.	E		6				
CRA - Phillipsburg, Kans.	E		5				
Sigmar - Three Rivers, Tex.	R			5			
Exxon - Baton Rouge, La.	E			8			
LaLandExpl - Mobile, Ala.	N			30			
Tesoro - Carrizo Springs, Tex.	E			7			
Hunt - Tuscaloosa, Ala.	E			14			
COPCO - Ventura, Calif.	N					15	
HIRI - Oahu, Hawaii	E					11	
Douglas - Paramount, Calif.	E					15	
Kern Co. - Bakersfield, Calif.	E					3	
Miscellaneous Net Additions (1%)		17	40	63	5	24	
1/1/76 Capacity		1,804	4,174	6,383	537	2,456	15,354
Texaco - Lockport, Ill.	E		25				
Exxon - Houston, Texas	E			250			
ARCO - Houston, Texas	E			95			
ECOL - Garyville, La.	N			200			
Champlin - Corpus Christi, Texas	E			60			
Socal - Richmond, Calif.	E					175	
Socal - El Segundo, Calif.	E					175	
Miscellaneous Net Additions (2%)		35	82	124	11	48	
1/1/77 Capacity		1,839	4,281	7,112	548	2,854	16,634
HIRI - Oahu, Hawaii	E					65	
Dow - Freeport, Texas	N			100			
Miscellaneous Net Additions (2%)		35	82	124	11	48	
1/1/78 Capacity		1,874	4,363	7,336	559	2,967	17,099
Shell - Gloucester Co., N.J.	N	150					
Texaco - Convent, La.	E			200			
Miscellaneous Net Additions (2%)		35	82	124	11	48	
1/1/79 Capacity		2,059	4,445	7,660	570	3,015	17,749

*Type: E - Expansion of Existing Capacity
 N - New Grassroots Refinery
 R - Reactivation of Idle Facilities

Source: Peer, E.L., "Trends in Refinery Capacity and Utilization - An Interim Update for U.S. Portion Only", Federal Energy Administration, December 1974.

ATTACHMENT 1
TYPICAL REFORMING PROCESS DATA
(200 PSIG Reactor Pressure)

Feedstock	250°/325°F. Light Arabian Naphtha		250°/325° F. Wilmington Naphtha	
P/N/A	70/19/11		24/76/10	
Operating Severity, RON	90	100	90	100
Product Yield, Vol. %:				
H ₂ SCF/B Feed	940	1,140	1,310	1,570
Fuel Gas FOE	2.3	5.5	0.5	1.3
C ₃	3.2	7.8	1.5	3.1
iC ₄	2.0	2.9	0.3	0.7
nC ₄	3.8	5.3	0.5	1.2
C ₅ /430°F.	85.2	73.9	93.0	88.6
Utilities:				
Fuel, Bbl/B Feed	.035	.037	.035	.037
Power, KWH/B Feed	1.3	1.3	1.3	1.3
Steam, Lbs/B Feed	45.6	45.6	45.6	45.6
Other Variable Costs, \$/B	.015	.020	.015	.020
Standard Capacity Increment, B/SD	27,800	25,000	27,800	25,000
Stream Operating Factor, %	84	84	84	84
1974 Investment - ISBL, M\$	16,200	16,200	16,200	16,200
Capacity Exponent	0.65	0.65	0.65	0.65
Initial Catalyst Charge, \$M	1,200	1,200	1,200	1,200
Paid-Up Royalty, \$M	1,100	1,100	1,100	1,100
Offsites As % ISBL	45	45	45	45

ATTACHMENT 2

TYPICAL DESULFURIZATION PLANT DATA

Feedstock	Arabian Light Fractions		
	375/500	500/620	1,000+
Boiling Range, °F.			
Weight Percent Sulfur	0.26	0.9	4.3
HDS Unit Feed Rate, B/CD	20,000	20,000	16,800
Battery Limits Investment, \$M:			
Desulfurization Unit	9,500	9,500	22,100
Hydrogen Generation	700	1,350	7,700
Sulfur Plant	200	700	3,000
Sub-Total	10,400	11,550	32,800
Offsites	4,800	5,650	16,700
Total Investment	15,200	17,200	49,500
Product Sulfur, Wt. %	0.03	0.10	1.00
Operating Costs, \$M/Year:			
Labor	300	350	1,050
Plant Overhead and General and Administrative Expense	150	170	525
Maintenance Materials	320	400	1,220
Utility and Energy Costs	1,250	1,220	7,320
Plant Supplies	80	100	315
Catalyst & Chemicals	-	-	950
Sub-Total	2,100	2,240	11,380
Capital Charges	3,920	4,440	12,780
Total Annual Costs	6,020	6,680	24,160
Cost Per Barrel of Desulfurized Product, \$	0.875	0.915	3.94